DUKE ENERGY KENTUCKY

ACCOUNT 3733 STREET LIGHTING - CUSTOMER POLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-L0						
NET SALVAGE PERCENT.. -25						
1962	755.64	605	945			
1963	2,782.60	2,206	3,478			
1964	5,748.22	4,508	7,185			
1965	4,665.23	3,619	5,832			
1966	7,777.78	5,966	9,722			
1967	3,479.48	2,637	4,349			
1968	13,702.27	10,265	17,128			
1969	9,039.84	6,689	11,300			
1970	10,509.18	7,676	13,136			
1971	11,268.50	8,127	14,086			
1972	9,421.14	6,705	11,776			
1973	19,731.84	13,853	24,665			
1974	26,908.55	18,623	33,636			
1975	21,885.45	14,928	27,357			
1976	28,100.64	18,886	35,126			
1977	18,884.29	12,495	23,605			
1978	33,299.53	21,686	41,624			
1979	47,010.63	30,126	58,763			
1980	64,740.61	40,787	80,926			
1981	37,233.17	23,053	46,541			
1982	31,008.79	18,864	38,761			
1983	11,307.29	6,751	14,134			
1984	14,332.94	8,391	17,916			
1985	16,882.67	9,693	20,945	158	16.22	10
1986	21,740.07	12,220	26,405	770	16.51	47
1987	18,167.17	9,999	21,606	1,103	16.79	66
1988	17,439.61	9,388	20,286	1,514	17.08	89
1989	22,810.66	11,995	25,919	2,594	17.38	149
1990	50,089.62	25,713	55,560	7,052	17.68	399
1991	58,187.99	29,118	62,918	9,817	17.99	546
1992	57,730.95	28,144	60,813	11,351	18.30	620
1993	53,177.85	25,238	54,534	11,938	18.61	641
1994	47,014.71	21,686	46,859	11,909	18.93	629
1995	57,876.96	25,900	55,965	16,381	19.26	851
1996	49,167.86	21,327	46,083	15,377	19.59	785
1997	65,963.90	27,678	59,806	22,649	19.93	1,136
1998	58,524.66	23,727	51,269	21,887	20.27	1,080
1999	27,323.39	10,679	23,075	11,079	20.62	537
2000	5,610.07	2,108	4,555	2,458	20.98	117
2001	66,321.77	23,931	51,710	31,192	21.34	1,462
2002	74.99	26	56	38	21.70	2
2004	314,329.75	98,751	213,380	179,532	22.46	7,993
2005	50,299.11	14,985	32,380	30,494	22.85	1,335

DUKE ENERGY KENTUCKY

ACCOUNT 3733 STREET LIGHTING - CUSTOMER POLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-L0						
NET SALVAGE PERCENT.. -25						
2006	120,624.10	33,975	73,413	77,367	23.24	3,329
2007	58,341.01	15,436	33,354	39,572	23.65	1,673
2008	85,866.40	21,217	45,846	61,487	24.07	2,555
2009	47,507.23	10,887	23,525	35,859	24.50	1,464
2010	3,892.91	819	1,770	3,096	24.95	124
2012	129,661.74	22,096	47,745	114,332	25.91	4,413
2013	125,758.30	18,707	40,422	116,776	26.43	4,418
2014	39,803.12	5,025	10,858	38,896	26.97	1,442
2015	187,697.27	19,239	41,571	193,051	27.54	7,010
2016	631,779.63	48,434	104,655	685,070	28.16	24,328
2017	190,026.68	9,264	20,017	217,516	28.83	7,545
2018	182,541.92	3,194	6,902	221,275	29.58	7,481
	3,295,827.68	928,045	1,926,193	2,193,592		84,276

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.0 2.56

DUKE ENERGY KENTUCKY

ACCOUNT 3900 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S1						
NET SALVAGE PERCENT.. -5						
1948	12,661.26	13,294	13,294			
1951	328.00	338	317	27	0.67	27
1977	3,297.18	2,602	2,442	1,020	8.69	117
2007	40,659.35	12,722	11,939	30,753	24.57	1,252
2008	59,235.18	17,131	16,077	46,120	25.36	1,819
2010	28,802.78	6,904	6,480	23,763	27.01	880
	144,983.75	52,991	50,549	101,684		4,095

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.8 2.82

DUKE ENERGY KENTUCKY

ACCOUNT 3910 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	2,796.07	1,468	1,470	1,326	9.50	140
2009	9,910.13	4,707	4,714	5,196	10.50	495
2013	1,587.47	437	438	1,149	14.50	79
2016	734.91	92	92	643	17.50	37
2017	9,544.40	716	717	8,827	18.50	477
2018	928.28	23	23	906	19.50	46
	25,501.26	7,443	7,454	18,048		1,274

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.2 5.00

DUKE ENERGY KENTUCKY

ACCOUNT 3911 ELECTRONIC DATA PROCESSING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	73,866.51	73,867	73,867			
2014	740,917.71	666,826	599,005	141,913	0.50	141,913
2015	171,406.92	119,985	107,782	63,625	1.50	42,417
2016	399,953.73	199,977	179,638	220,316	2.50	88,126
2017	375,483.33	112,645	101,188	274,295	3.50	78,370
2018	709,786.48	70,979	63,760	646,027	4.50	143,562
	2,471,414.68	1,244,279	1,125,240	1,346,175		494,388

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.7 20.00

DUKE ENERGY KENTUCKY

ACCOUNT 3920 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-S3						
NET SALVAGE PERCENT.. 0						
2016	17,626.65	3,672	2,339	15,288	9.50	1,609
2017	97,337.15	12,167	7,749	89,588	10.50	8,532
2018	413,742.04	17,241	10,979	402,763	11.50	35,023
	528,705.84	33,080	21,067	507,638		45,164

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.2 8.54

DUKE ENERGY KENTUCKY

ACCOUNT 3921 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-R2.5						
NET SALVAGE PERCENT.. +5						
1999	15,736.15	11,901	14,617	332	3.67	90
2000	5,838.07	4,289	5,268	278	4.08	68
2001	21,763.00	15,460	18,988	1,687	4.54	372
2003	14,278.00	9,344	11,476	2,088	5.60	373
2005	26,234.28	15,466	18,996	5,927	6.83	868
2006	92,022.48	50,995	62,632	24,789	7.50	3,305
2016	78,567.76	9,661	11,866	62,773	15.67	4,006
	254,439.74	117,116	143,843	97,875		9,082

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.8 3.57

DUKE ENERGY KENTUCKY

ACCOUNT 3940 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1994	1,028.38	1,008	1,008	20	0.50	20
1997	6,942.62	5,971	5,974	969	3.50	277
1998	16,223.30	13,303	13,309	2,914	4.50	648
2000	109,708.96	81,185	81,220	28,489	6.50	4,383
2001	51,974.41	36,382	36,397	15,577	7.50	2,077
2002	37,932.62	25,036	25,047	12,886	8.50	1,516
2003	4,809.80	2,982	2,983	1,827	9.50	192
2005	25,940.45	14,008	14,014	11,926	11.50	1,037
2008	380,978.53	160,011	160,079	220,900	14.50	15,234
2009	2,959.10	1,124	1,124	1,835	15.50	118
2010	176,619.28	60,051	60,077	116,542	16.50	7,063
2011	193,492.90	58,048	58,073	135,420	17.50	7,738
2012	212,729.10	55,310	55,334	157,395	18.50	8,508
2013	139,430.69	30,675	30,688	108,743	19.50	5,577
2014	39,966.78	7,194	7,197	32,770	20.50	1,599
2015	135,407.94	18,957	18,965	116,443	21.50	5,416
2016	489,557.71	48,956	48,977	440,581	22.50	19,581
2017	327,834.85	19,670	19,678	308,157	23.50	13,113
2018	63,619.75	1,272	1,273	62,347	24.50	2,545
	2,417,157.17	641,143	641,417	1,775,740		96,642

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.4 4.00

DUKE ENERGY KENTUCKY

ACCOUNT 3960 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2008	11,770.00	6,199	6,757	5,013	7.10	706
	11,770.00	6,199	6,757	5,013		706

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1 6.00

DUKE ENERGY KENTUCKY

ACCOUNT 3970 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	154,485.86	128,738	128,767	25,719	2.50	10,288
2007	166,461.37	127,621	127,650	38,811	3.50	11,089
2009	107,358.47	67,993	68,008	39,350	5.50	7,155
2010	1,387,831.33	786,442	786,621	601,210	6.50	92,494
2011	478,464.22	239,232	239,286	239,178	7.50	31,890
2012	8,837.90	3,830	3,831	5,007	8.50	589
2013	22,988.34	8,429	8,431	14,557	9.50	1,532
2014	330,246.90	99,074	99,096	231,151	10.50	22,014
2015	17,836.10	4,162	4,163	13,673	11.50	1,189
2016	248,081.50	41,348	41,357	206,724	12.50	16,538
2017	658,842.01	65,884	65,899	592,943	13.50	43,922
2018	432,015.03	14,399	14,403	417,612	14.50	28,801
	4,013,449.03	1,587,152	1,587,512	2,425,937		267,501

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.1 6.67

Appendix A

JOHN SPANOS DEPRECIATION EXPERIENCE

Q. PLEASE STATE YOUR NAME.

A. My name is John J. Spanos.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin

Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of

Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company;

Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. HAVE YOU SUBMITTED TESTIMONY TO ANY STATE UTILITY COMMISSION ON THE SUBJECT OF UTILITY PLANT DEPRECIATION?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana

Utility Regulatory Commission; the California Public Utilities Commission; the

Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. HAVE YOU HAD ANY ADDITIONAL EDUCATION RELATING TO UTILITY PLANT DEPRECIATION?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. DOES THIS CONCLUDE YOUR QUALIFICATION STATEMENT?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	YearJurisdiction	Docket No.	Client Utility	Subject
01.	1998PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and	Depreciation
29.	2004RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation

32.	2005IL CC	05-	North Shore Gas Company	Depreciation
33.	2005IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.		Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.		Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS082, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	YearJurisdiction	Docket No.	Client Utility	Subject
66.	2007PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009TX PUC	37744	Entergy Texas	Depreciation
95.	2009TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	YearJurisdiction	Docket No.	Client Utility	Subject
99.	2009OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010IN URC		Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	YearJurisdiction	Docket No.	Client Utility	Subject
133.	2011FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012TX PUC		Aqua Texas	Depreciation
155.	2012PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013NY PSC	13-E-0030, 13-G-0031,	Consolidated Edison of New York	Depreciation
162.	2013PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	YearJurisdiction	Docket No.	Client Utility	Subject
166.	2013WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	YearJurisdiction	Docket No.	Client Utility	Subject
200.	2014KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/	Depreciation
212.	2015NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

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	YearJurisdiction	Docket No.	Client Utility	Subject
233.	2016PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016IN URC		Indianapolis Power & Light	Depreciation
245.	2016AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western	Depreciation
247.	2017TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017FERC	ER17-217	Jersey Central Power & Light	Depreciation
259.	2017FERC	ER17-211	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER17- _	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	Docket Nos. ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.3	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

DIRECT TESTIMONY OF

JOHN A. VERDERAME

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 3, 2019

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I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame, and my business address is 526 S. South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Progress, Inc. (Duke Energy Progress) as Managing Director, Trading and Dispatch. Duke Energy Progress is the utility formerly known as Progress Energy Inc., (Progress Energy) located in North and South Carolina. As part of the merger integration process, Duke Energy Progress now provides various administrative and other services to the regulated affiliated companies within Duke Energy Corporation (Duke Energy Corp.), including Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 18 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the

Progress Energy regulated utilities. In 2005, I was promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was promoted to my current position.

Q. HAVE YOU EVER TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I have previously testified in the Company's Fuel Adjustment Clause (FAC) proceedings, its last base electric rate case, Case No. 2017-00321, as well as other cases that have involved the Company's participation in energy and capacity markets.

Q. PLEASE SUMMARIZE YOUR DUTIES AS MANAGING DIRECTOR, TRADING AND DISPATCH.

A. As Managing Director, Trading and Dispatch of Duke Energy, I am responsible for Gas, Oil, and Power Trading and Generation Dispatch on behalf of the Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I am responsible for Duke Energy Kentucky's generation dispatch, unit commitment, 24-hour real-time operations, and plant communications related to short-term generating maintenance planning. I lead the teams responsible for managing the Company's capacity position with respect to meeting its Fixed Resource Requirement (FRR) obligation as a member of PJM Interconnection, L.L.C. (PJM), for the submission of the Company's supply offers and demand bids in PJM's day-ahead and real-time electric energy (collectively Energy Markets) and ancillary services markets (ASM), as well as those managing the Company's short-term supply position to ensure that the Company has adequate economic resources committed to serve its retail customers' electricity needs. In that respect, my teams are also responsible for any financial hedging done to mitigate exposure to short-term energy prices and congestion risks.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I provide an overview of the Company's generating resources to meet its customer load obligations and provide safe, reliable and adequate service. I briefly describe Duke Energy Kentucky's resource planning process that is used to ensure it continues to meet its Kentucky customers' load requirements. I then discuss the Company's participation in PJM as it pertains to the energy and capacity markets and discuss the customer benefits that the Company's PJM membership provides. Finally, I sponsor Filing Requirement (FR) 16(7)(h)(7) and certain forecasted financial data that I provided to Duke Energy Kentucky witness Mr. Christopher Jacobi for his use in preparing the Company's forecast.

II. <u>OVERVIEW OF DUKE ENERGY'S CURRENT GENERATING RESOURCES</u>

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF HOW DUKE ENERGY KENTUCKY MEETS ITS KENTUCKY LOAD OBLIGATIONS.

A. Duke Energy Kentucky currently owns and operates approximately 1,062 net installed megawatts (MW) of generating capacity, provided by two assets. Base load requirements are met by the East Bend Unit 2 Generating Station (East Bend). East Bend is an approximate 600-megawatt (MW) (net rating) coal-fired base load unit located along the Ohio River in Boone County, Kentucky. The Company's peaking requirements are met with the Woodsdale Generating Station (Woodsdale). Woodsdale is a six-unit natural gas-fired combustion turbine (CT) with approximately 462 MW (net summer rating) located in Trenton, Ohio. The net ratings represent the amount of power that the Company can dispatch from the plants after some portion of the gross power output is used to power the plant machinery. These assets are dispatched into PJM, which maintains functional control of the transmission system within its footprint including the Duke Energy Ohio/Kentucky system. To the extent Duke Energy Kentucky is able to monetize its assets to produce off-system sales through PJM, customer receive the majority of those net revenues (or costs) through the Company's profit sharing mechanism (Rider PSM).

Q. HOW DOES DUKE ENERGY KENTUCKY MANAGE THE RISKS OF EXPOSURE TO MARKET PRICES FOR ITS CUSTOMERS?

A. Duke Energy Kentucky manages these risks through two strategies. First, the Company operates under a Commission–approved Back-Up Power Supply Plan. The Commission approved the Company's most recent Back-Up Power Supply Plan on May 31, 2017 in Case No. 2017-00117. Second, the Company manages its long-term strategy through the integrated resource planning (IRP) process.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S BACK-UP SUPPLY PLAN.

A. Duke Energy Kentucky conducted a thorough analysis of back-up supply opportunities that were available to select what the Company believes appropriately balances the competing interests of finding the most reasonable and reliable solution for customers that is at the lowest possible cost, to obtain back-up power. The Company's strategy is to continue to manage the risks through the PJM daily energy market during forced outages and use fixed forward contract purchases during scheduled outages. This mitigates the risk of price spikes during scheduled outages because the price for back-up power would be fixed.

The Company's strategy provides the flexibility to optimize the actual outage schedule under changing power market and unit availability conditions through the liquid energy markets. Duke Energy Kentucky can make its forward contract purchase a few months in advance of the scheduled outages, without paying a premium to lock in the prices for a three-year period. If prices appear to be increasing, the plan provides the flexibility to make the forward contract purchases for long-term periods. If prices are flat or falling, the Company can postpone these purchases. The Company's plan provides flexibility to modify executed forward contract positions if scheduled outage dates are modified, by utilizing the liquidity of the Intercontinental Exchange (ICE) to unwind existing contracts and purchase new contracts to match new scheduled outage dates. The Company continues to examine business interruption insurance products to complement its risk management strategy. Duke Energy Kentucky has been using this strategy to successfully manage risks in the energy markets since approximately 2006. History has shown that the Company has been capable of managing these energy risks for its customers.

Q. DOES DUKE ENERGY KENTUCKY PROPOSE TO MAKE ANY CHANGES TO THE WAY IT MANAGES CUSTOMER EXPOSURE TO MARKET PRICES?

A. Yes. Duke Currently, Duke Energy Kentucky manages customer market price exposure during periods of scheduled generation outages. The Company proposes, utilizing the same financial instruments, to expand that risk mitigation to include periods during forced generation outages.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING THIS CHANGE?

A. The annual base revenue requirement approved by the Commission, in Case No. 2006-00152, included recovery of $5 million for replacement power expenses due to forced generation outages that are not recoverable in the fuel adjustment clause. In its Order in Case No. 2017-00321, the Commission reduced the amount being recovered in base rates to approximately $1.6 million; however, the Commission also approved a request by the Company to defer the difference between the actual annual amount of this expense and the $1.6 million being recovered in base rates. To the extent actual costs exceed the $1.6 million base amount in a given year, the Company records a regulatory asset and will recover the difference at some point in the future. Conversely, if the actual costs less than $1.6 million in a given year, the Company records a regulatory liability to reflect that it owes customers as a result of collecting more in base rates than its actual costs. This mechanism ensures that the Company fully recovers no more and no less than its actual costs related to replacement power and similarly ensures that customers pay no more and no less than the actual costs of the replacement power.

During scheduled outages, the Company is allowed to recover costs of replacement power via its fuel adjustment clause. Whether through base rates, for replacement power due to forced outages, or through the fuel adjustment clause, for replacement power during scheduled outages, customers will ultimately pay only the actual cost of the replacement power. As customers have similar exposure to short term market prices during periods of both scheduled and forced generation outages, the Company believes it is in customers' best interest to manage that price exposure in both cases. Since forced outages are by their nature unexpected, the forced outage risk mitigation strategy will likely predominantly include short term financial products to mitigate price exposure. Depending on the anticipated length of the forced outage, the Company proposes to utilize daily, weekly, and potentially monthly financial futures contracts to reduce replacement power cost volatility.

Q. HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO PASS CREDITS AND CHARGES FROM HEDGING FORCED GENERATION OUTAGES THROUGH TO CUSTOMERS?

A. Duke Energy Kentucky proposes to treat hedge results; both gains and losses exactly as it currently treats those resulting from scheduled generation outages.

Q. ARE YOU FAMILIAR WITH THE INTEGRATED RESOURCE PLANNING PROCESS FOR DUKE ENERGY KENTUCKY?

A. Yes. While I am not responsible for production of the IRP, I am generally familiar with it. Duke Energy Kentucky files its integrated resource plan (IRP) approximately every three years. The Company filed its last IRP with the Commission in Case No. 2018-00195. Although this IRP provided a snapshot of Duke Energy Kentucky's resource planning at that point in time, IRP planning is a dynamic process that is periodically updated.

Q. PLEASE GENERALLY DESCRIBE THE IRP PLANNING PROCESS.

A. The IRP planning process assesses various supply-side, demand-side and emission compliance alternatives to develop a long-term, cost-effective portfolio to provide customers with reliable service at reasonable costs. The IRP planning process involves various assumptions such as future energy prices, future environmental compliance requirements and reliability constraints.

The Duke Energy's load forecasting group develops the load forecast by: (1) obtaining service area economic forecasts primarily from Moody's Analytics; (2) preparing an energy forecast by applying statistical analysis to certain variables such as number of customers, economic measures, energy prices, weather conditions, *etc.;* and (3) developing monthly peak demand forecasts by statistically analyzing weather data. The Company updates the load forecasts on a regular basis and the updated load forecasts are used for all modeling analysis. It is important to note that while Duke Energy Kentucky develops internal load forecasts for system planning purposes, the actual load forecast and the Duke

Energy Kentucky PJM load obligation, which includes peak coincidence factors and system reserve requirements is calculated by PJM, and can differ slightly from the Company's internal forecast.

Q. WHAT RELIABILITY CONSTRAINT ASSUMPTIONS ARE NECESSARY TO DEVELOP AN IRP?

A. A reliability constraint is included in the modeling process by the inclusion of a 15% reserve margin.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PLANNING RESERVE MARGIN AND HOW IT IS CALCULATED.

A. In the IRP, the Company uses a 15% reserve margin which is meant to cover unit outages over the IRP modeling period to ensure long term reliability. For IRP purposes, this is done on an UCAP basis versus the PJM planning reserve margin which is calculated on an ICAP basis. While there are differences in the calculation, both approaches target similar levels of reliability. The reason that the Company does not use the PJM approach for long-term planning is that it would require long-term forecast for some variables such as unit outages or coincidence factors. Most utilities in the nation have reserve margins between 13% and 20%.

Q. PLEASE EXPLAIN HOW THE COMPANY MODELS THE DISPATCH OF ITS GENERATING STATIONS.

A. The Company utilizes a commercially available production cost model (Prosym) to model the dispatch of the Duke Energy Kentucky system as well as economic purchase and sales from/to the PJM market. All of the Company's generating units are represented in the model with their key characteristics, such as capacity, fuel type, heat rate, and emission rates. Other inputs include projected fuel costs for each unit, planned outages, forced outage rates, the market value for emission allowances, the market price for power, and the Company's load forecast for native load customers. For the period forecasted, the model provides projections of how generating units are expected to operate, including projections of fuel consumption and emissions.

Q. WHAT ARE THE COMPANY'S LOAD REQUIREMENTS?

A. The utility's load in 2019 is approximately 850 MW and when grossed up for the 15% reserve margin results in a load requirement approaching 1,000 MW. As the level and characteristics of the load change over time, the Company routinely assesses resource adequacy and adjusts its plans accordingly to ensure reliability in a cost-effective way for customers. Should new load come into the service territory, the Company will evaluate how that load fits within the overall utility's obligation in determining appropriate resource additions.

Q. DOES DUKE ENERGY KENTUCKY CURRENTLY HAVE SUFFICIENT CAPACITY TO MEET ITS KENTUCKY CUSTOMER LOAD OBLIGATIONS?

A. Duke Energy Kentucky currently has sufficient capacity to meet its load obligations; however, short-term capacity purchases may be necessary to maintain sufficient reserves and meet its capacity obligations in PJM. As was approved by the Commission in the Company's last electric rate case, 2017-00321, Duke Energy Kentucky uses its Profit-Sharing Mechanism, Rider PSM, to address short-term capacity shortfalls in its FRR plan through short-term capacity purchases as well as for netting any tariffed capacity co-generation purchases including from qualified facilities as is required under the Public Utility Regulatory Policies Act (PURPA).

Duke Energy Kentucky continually evaluates its load obligations and its portfolio to ensure that there is adequate supply available. This evaluation factors in the unique circumstances and challenges the Company faces in its Northern Kentucky service territory. Duke Energy Kentucky is experiencing some load growth in its service territory and must plan to make sure the Company is able to meet such demand. While the East Bend and Woodsdale generating stations have been reliable and economic assets to satisfy base load and peaking obligations, the fact remains that Duke Energy Kentucky is heavily dependent upon these two stations to serve customers. As load demand grows, the Company's portfolio of resources should diversity to ensure there is a continued access to a stable, economic energy supply.

In an attempt to address the diversification issue as well as the increasing likelihood of carbon regulation, the Company believes that a measured approach to transitioning the generation fleet makes sense for customers. The most recent IRP includes 10 MW of solar and 2 MW of storage every year to start this transition. Particular projects may be smaller or larger depending on site size or in order to take advantage of any economies of scale. Additionally, the Company continues to consider and evaluate other potential supply-side resources and solutions that may be in the best interests of its Kentucky customers.

III. <u>DUKE ENERGY KENTUCKY'S PARTICIPATION IN PJM</u>

Q. PLEASE GENERALLY DESCRIBE PJM.

A. Duke Energy Kentucky has been a member of PJM since January 1, 2012. PJM is the nation's first fully functioning regional transmission organization (RTO) and manages the power grid and wholesale electric market for all or parts of thirteen states and the District of Columbia. PJM's electric market consists of energy, capacity, ancillary services markets (ASM), and a financial transmission rights market. PJM's operation is governed by agreements approved by the Federal Energy Regulatory Commission (FERC), including the Operating Agreement, Open Access Transmission Tariff (OATT), and the Reliability Assurance Agreement (RAA). As a member of PJM, Duke Energy Kentucky is subject to these agreements, which among other things require Duke Energy Kentucky to offer all of its available generation to PJM and to purchase its customer energy load requirements from the PJM Day-Ahead or Real-Time Energy Markets. The Day-Ahead and Real-Time Energy Markets are collectively referred to as the PJM Energy Market for the remainder of my testimony.

Q. PLEASE EXPLAIN HOW THE COMPANY MEETS ITS ENERGY NEEDS THROUGH THE PJM ENERGY MARKET.

A. Consistent with its PJM membership, the Company meets all energy needs through the PJM Energy Market and does not currently purchase any energy outside of PJM. Through PJM's Day-Ahead Market, market participants can mitigate their exposure to real-time price risk by selling available generation and purchasing forecasted demand in the Day-Ahead Energy Market. Duke Energy

Kentucky submits demand bids and supply offers as both a load serving entity (LSE) and a generator owner, respectively. Thus, the Company simultaneously functions as both a buyer and seller to serve its retail electric customers.

Q. PLEASE BRIEFLY DESCRIBE THE PJM ENERGY MARKET.

A. PJM administers its energy markets utilizing locational marginal pricing (LMP). LMP can be broadly defined as the value of one additional megawatt of energy at a specific point on the electric grid. In PJM, LMP is composed of three components: the system marginal energy price; the transmission marginal congestion price; and the marginal loss price. Both the Day-Ahead and Real-Time Energy Markets are based on supply offers and demand bids submitted to PJM by market participants or actual customer demand, including both generator owners (as sellers) and load serving entities (as buyers).

The Day-Ahead Energy Market provides a means for market participants to mitigate their exposure to price risk in the Real-Time Energy Market. The Day-Ahead Energy Market also provides meaningful information to PJM regarding expected real-time operating conditions for the next day, which enhances PJM's ability to ensure reliable operation of the transmission system and economically serve customer demand. The Real-Time Energy Market functions as a balancing market between generation and load in real-time. Through the PJM Energy Markets and the LMP price signals, PJM provides a market-based solution to value and thus manage energy production, transmission congestion, and marginal losses in the PJM region to meet demand in the most cost-effective way.

Q. PLEASE DESCRIBE PJM'S ASM AND HOW DUKE ENERGY KENTUCKY PARTICIPATES IN THOSE MARKETS.

A. PJM's ASM consists of the following services:

- Synchronized Reserves, which provide energy during an unexpected period of need within 10 minutes;
- Non-Synchronized Reserves, which also provide energy during an unexpected period of need and within 10 minutes, but which are typically off-line;
- Regulation and Frequency Responsive Reserves, which are utilized to continuously balance resources with demand and maintain interconnection frequency;
- Day-Ahead Scheduling Reserves, a 30-minute day-ahead reserve product;
- Black Start Service, which provides energy for restoration of the grid following a shutdown condition;
- Reactive Supply and Voltage Control, which is produced by capacitors and generators and absorbed by reactors and other inductive devices;
- Reactive Services, which is to maintain transmission voltages within acceptable limits; and
- Synchronous Condensing, which are utilized to adjust reactive power conditions on the electric grid.

PJM's ASM is co-optimized within the PJM Energy Markets to minimize overall production costs and ensure reliability across the PJM footprint.

In addition to the physical Energy Market and ASM, PJM offers financial products that can be utilized to hedge exposure to the Energy Markets. Virtual transactions can hedge risk in the Real-Time Energy Market, and financial transmission rights can hedge exposure to day-ahead congestion costs. Financial transmission rights auctions are conducted annually and monthly. Financial transmission rights are defined with source and sink points that entitle and obligate the holder to a stream of revenues or charges based on the hourly day-ahead congestion price differences across the defined path. Duke Energy Kentucky utilizes financial transmission rights to manage the congestion risk from its generation stations to its load zone. Virtual transactions clear in the Day-Ahead Energy Market as virtual generators and loads at specific points on the grid. Virtual transactions settle based on the difference between the day-ahead and real-time LMP at the specific node. Duke Energy Kentucky may utilize virtual transactions to hedge generator performance risk, primarily during start up or as a potential operational contingency.

Other non-PJM operated financial markets that are based on PJM market settlements exist. Duke Energy Kentucky participates in these financial markets to hedge Duke Energy Kentucky's customers' exposure to day-ahead and real-time energy prices when its generation stations are unavailable due to planned maintenance outages. These instruments can also be utilized to manage customers' exposure to day-ahead and real-time energy prices when generation stations are unavailable due to forced outage conditions.

Q. PLEASE EXPLAIN HOW PJM DISPATCHES GENERATING RESOURCES TO MEET DEMAND.

A. PJM performs a security constrained economic commitment and least-cost security constrained economic dispatch process that simultaneously optimizes energy and reserves for all generation in its footprint in determining which assets to commit and dispatch. This process considers the various, unique challenges faced in reliably and economically supplying energy to all loads across its footprint, most significantly aligning the production of energy simultaneously with the volatility in demand within the capability of the transmission network. PJM must continually account for the fact that customer demand is dynamic in nature, fluctuating over the course of a day, week, and season, while analyzing factors such as costs and operating characteristics of generation from different types of units within its entire footprint and expected and unexpected conditions on the transmission network that affect which generation units can be used to serve load economically and reliably given the numerous constraints that must be considered. Because of these challenges, PJM's dispatch process "is designed to be an optimization process so that a reliable supply of electricity at the lowest cost possible under the conditions prevailing in each dispatch time interval can be delivered."[1]

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[1] FERC Docket AD05-13-000, *Report on Security Constrained Economic Dispatch by the Joint Board of PJM/MISO Region*, Attachment 1, at pg. 5 (May 24, 2006).

Importantly, PJM's decisions as to which generating units should be dispatched are not made exclusively based on the individual unit's cost. Although the price of energy at a generating unit is certainly important, PJM's dispatch process must consider a number of factors, including system-wide reliability, transmission grid congestion and losses, and numerous operational conditions and constraints. PJM has access to complete information regarding the operation of its Day-Ahead and Real-Time Energy Markets in making the determination to commit and dispatch a unit. Because of the efficient and informed nature of PJM's dispatch methodology, a utility's energy purchases in PJM's Day-Ahead and Real-Time Energy Markets are the most efficient and economic means available to satisfy customer load. Stated another way, energy acquired by all load serving entities from PJM are necessarily and, by definition, purchased on an economic dispatch basis.

Q. PLEASE BRIEFLY EXPLAIN HOW DUKE ENERGY KENTUCKY'S CURRENT GENERATION PORTFOLIO PARTICIPATES AND IS DISPATCHED IN THE DAY-AHEAD AND REAL-TIME ENERGY MARKETS.

A. Under the terms of PJM's RAA, as a FRR entity and generation owner in PJM, Duke Energy Kentucky is under a must-offer requirement to offer all generation committed to the FRR plan into the Day-Ahead Energy Market. The generating units are offered by Duke Energy Kentucky, as the market participant, with commitment status designations including: Must Run, Economic, Emergency, Fixed Gen, and Unavailable. Units offered with a Must Run status are committed and are generally dispatched near minimum load or the output of the generating unit is decreased ("dispatched down") during periods when the marginal cost of the unit is above the LMP solved by the dispatch model, or the generating unit is dispatched near full load or the output is increased ("dispatched up") during periods when the marginal cost of the unit is below the LMP solved by the dispatch model. A commitment status of "Economic" means that a generating unit is available to be committed by PJM in the Day-Ahead or Real-Time market. Economic units will generally be committed if their "all in" costs, including startup costs, are economic across a period. Emergency status indicates that a unit is available to be committed by PJM in the case of an emergency event. Fixed Gen units are committed but intend to remain fixed or otherwise not follow PJM real-time dispatch. Unavailable status means that a generating unit is not available to be committed.

In making the decision regarding an individual unit's offer status, the Company considers various factors such as unit availability, forecasted locational marginal prices, unit generation production cost, PJM impacts (Day-Ahead Operating Reserve credits, balancing operating reserve changes, *etc.*), and the capability, risk, and economic impact from cycling the generating unit off-line and/or on-line. Before making any generation unit offer, Company personnel engage in a daily planning process designed to minimize the total customer cost by maximizing each unit's economic value.

Each generating unit is offered hourly with a segmented incremental energy price pair quantity and ancillary service offer curve across the unit's operational range as well as a start-up cost, no-load cost, and operating parameters. The hourly offers are based on numerous factors, including but not limited to, the daily fuel cost, unit efficiency, emissions and variable operations and maintenance (O&M) costs, maximum and minimum loadings, and plant output availability and physical characteristics. Unit commitment status is determined based upon unit availability, marginal energy costs, expected impact of certain PJM charges and credits, and anticipated market clearing prices.

Day-ahead generation unit offers are submitted to PJM by 10:30 Eastern Prevailing Time the day prior to energy flow. Generally, by 13:30 Eastern Prevailing Time that day, following execution of a security constrained unit commitment model, PJM posts energy and ancillary services awards for the following day. These awards are financially binding on both Duke Energy Kentucky and PJM.

In real-time, Duke Energy Kentucky makes hourly updates to the energy and ancillary service offers, primarily with respect to unit availability, but also taking into account the unit's operating parameters. The Duke Energy Kentucky generation dispatchers follow PJM generation dispatch signal instructions and relay necessary instructions to the generation stations.

It is possible that in real-time, despite receiving a day-ahead energy award, PJM dispatch signals will instruct Duke Energy Kentucky units to move to generation loadings other than their day-ahead award level. These instructions are based on the real-time energy and ancillary services needs of the overall system as manifested through LMP price signals at the generator bus. If the real-time LMP is below a unit's marginal cost of energy, PJM will likely reduce output, or possibly delay or cancel a unit startup. Conversely, if system conditions have changed from day-ahead results, PJM may direct a Duke Energy Kentucky unit to start up even without a day-ahead energy award. Duke Energy Kentucky has an obligation and financial incentive to follow PJM dispatch instructions.

Q. PLEASE DESCRIBE HOW DUKE ENERGY'S GENERATING STATIONS PERFORM IN PJM'S ENERGY MARKETS.

A. Duke Energy Kentucky offers its generation and bids its load into the PJM market. For the Duke Energy Kentucky generating capacity, the Company offered its resources in an FRR capacity plan consistent with the Commission's directive and approval of the Company becoming a PJM member in Case No. 2010-00203. The generating resources that are committed in the FRR plan have a must-offer obligation for their energy in the Day-Ahead Energy Market.

Duke Energy Kentucky's Miami Fort 6 station (Miami Fort 6), a 163-Megawatt (net) coal-fired unit retired on June 1, 2015. At that time, Miami Fort 6 ceased dispatching energy in the PJM Energy Markets and had to be removed from the Company's FRR capacity plan. Duke Energy Kentucky's other coal unit, East Bend, continues to compete favorably in the PJM market, with typical dispatch of this unit at full load during on-peak periods.

The Company's six natural gas-fired combustion turbines at Woodsdale station, which operate as peaking units, continue to see limited dispatch within the

PJM energy markets. However, these units can and do clear for other ASM products, even though the actual generating unit may remain off-line during this time.

PJM commits and dispatches these resources via their security constrained unit commitment and least-cost economic dispatch software by modeling the Duke Energy Kentucky generating resources with all other generating resources in the PJM wholesale energy market. If not committed day-ahead, the Woodsdale units may still be called upon in real-time. There are separate LMPs calculated for Day-Ahead versus Real-Time Markets that are paid to the generators or charged to the load.

Q. PLEASE DESCRIBE THE PERFORMANCE OF DUKE ENERGY KENTUCKY'S GENERATING RESOURCES IN THE ASM.

A. Each of PJM's ASM products is cleared separately with different prices for each product. In addition, PJM reimburses service providers such as Duke Energy Kentucky for black start and reactive services. Woodsdale is currently a black start unit in the Company's black start plan and, in addition, two of the units are reimbursed for certain costs to provide black start service to PJM. Duke Energy Kentucky continues to operate its generating resources to optimize revenues available in PJM for ancillary services, black start, and reactive service as well as energy and capacity markets in a reliable manner for the benefit of customers and shareholders.

Q. PLEASE DESCRIBE THE PJM CAPACITY MARKET.

A. PJM's capacity market is called RPM, which is an acronym for Reliability Pricing Model. The purpose of RPM is to provide a market construct that enables PJM to secure adequate generation resources to meet the reliability needs of the RTO. The RPM construct and the associated rules regarding how PJM members participate in the PJM capacity market is described within the PJM OATT and RAA. The PJM capacity market operates on a planning period that spans twelve months beginning June 1st and ending May 31st of each subsequent year (Delivery Year). In PJM, the capacity market structure is intended to provide transparent forward market signals that support generation and infrastructure investment. There are two ways for a PJM member to participate in the RPM capacity structure: 1) through the RPM baseline procurement auctions; or 2) as a self-supply FRR entity. The baseline procurement auction is called a base residual auction (BRA). BRAs are conducted three years in advance of the actual Delivery Year in order to allow bidders to complete construction of projects that clear the BRA. The PJM capacity market is designed to provide incentives for the development of generation, demand response, energy efficiency, and transmission solutions through capacity market payments.

Another important component of RPM is that price signals are locational, and designed to recognize and quantify the geographical value of capacity. PJM divides the RTO into multiple sub-regions called locational delivery areas (LDAs) in order to model the locational value of generation.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY CURRENTLY PARTICIPATES IN THE PJM CAPACITY CONSTRUCT.

A. Consistent with the Commission's Order in Case No. 2010-00203, Duke Energy Kentucky is an FRR Entity in PJM. As a condition of Duke Energy Kentucky becoming a member of PJM, the Commission required the Company to participate in PJM as an FRR entity until such time as it received Commission approval to participate in the PJM capacity auctions. To date, the Company has not requested such permission, but continues to evaluate the merits of exiting the FRR obligation and becoming a full RPM auction participant.

Q. PLEASE BREIFLY EXPLAIN PJM'S FRR PROCESS.

A. The PJM OATT and RAA specify the obligations and compensation to LSEs for supplying capacity. The FRR process is an alternative means for a PJM LSE such as Duke Energy Kentucky to satisfy its customer capacity obligation under the PJM RAA. Under the FRR construct, an LSE must annually submit a preliminary three-year forward, and a final current year FRR capacity plan that meets a PJM defined customer capacity obligation (FRR Plan). The FRR Plan must identify the unit-specific generating or demand response resources that will be providing the MWs of capacity that will fulfill the LSE's customer obligation. FRR allows the LSE to match its customer reliability requirement to its own generation, demand response, energy efficiency and/or transmission resources, while still being permitted to sell some or all of its excess supply into RPM. Duke Energy Kentucky would face severe penalties and limitations on its ability to choose the

FRR option if PJM were to deem either its initial or final FRR plans to be insufficient or it's generation otherwise non-compliant with PJM requirements.

Q. PLEASE EXPLAIN WHAT BEING AN FRR ENTITY MEANS FOR DUKE ENERGY KENTUCKY.

A. As an FRR entity, Duke Energy Kentucky must secure and commit unit-specific generation resources to meet the full load capacity requirements for its customers in advance of the PJM BRA through its FRR Plan. The FRR Plan is forward-looking in that it covers the Delivery Year three years into the future. For example, as part of its most recent FRR plan submitted in 2019, Duke Energy Kentucky must own or contract and commit the unit specific generation resources to satisfy its forecasted load requirements for the period from June 1, 2022, through May 31, 2023. Presently, the load requirements include both the forecasted load of Duke Energy Kentucky's customers, as well as the reserve requirement mandated by PJM.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE PHRASE UNIT-SPECIFIC GENERATION RESOURCES.

A. A unit-specific generation resource, as the phrase implies, simply means a specific generating resource that meets the eligibility requirements defined by PJM. PJM eligible resources include both physical and demand-side management resources. Duke Energy Kentucky must identify the specific generation resources it owns or has contracted for to provide capacity to meet its entire Delivery Year FRR obligation. Unit-specific capacity is distinguishable from the more "generic" buy-bid capacity that may be purchased through the BRA or incremental auctions of

PJM. The capacity product available for purchase in those auctions is not directly tied to a specific generator, so it cannot, in itself, be used to satisfy an FRR plan obligation. While sellers in the BRA identify the generation resource offered into the auction, the end product is not so specific. The entire generator performance obligation in the BRA is to PJM, not the purchaser of the buy-bid capacity. From the purchaser's perspective, buy-bid capacity has guaranteed deliverability and performance by PJM. This is distinguishable from the FRR entity where the performance obligation of generation committed to FRR plans is the responsibility of the FRR entity.

As such, Duke Energy Kentucky has similar performance risk to RPM entities, but less flexibility to adjust its plan to account for changes in its resource requirements between the BRA and the Delivery Year than an RPM participant who can simply buy and sell capacity to meet its needs through the BRA.

Q. HAVE THERE BEEN ANY RECENT SHIFTS IN DUKE ENERGY KENTUCKY'S ACCESS TO UNIT-SPECIFIC GENERATION RESOURCES?

A. Yes. For the 2020/2021 Delivery Year, capacity in the Duke Energy Ohio Kentucky (DEOK) zone cleared with a LDA adder of $53.47/ MW-day to the $76.53/ MW-day general clearing price known as "Rest of RTO." The total clearing price for the DEOK zone was $130/ MW-day. While there is no guarantee that DEOK zone capacity will continue to clear at a premium to the more generic capacity in the RTO, and in fact subsequent delivery year has cleared with the Rest of RTO, this zonal separation does create the potential that

Duke Energy Kentucky's access to unit-specific capacity could be constrained and even priced at a premium in the future. This loss of liquidity exists regardless of whether Duke Energy Kentucky remains an FRR entity or moves at some point to full RPM participation for as long as the zonal separation exists. Because Duke Energy Kentucky's resources generally match expected load obligation for the planning period, continued investment in the Company's existing generating assets for dedicated use in its FRR plan is a crucial piece of the Company's strategy to serve customers. As such, deviations from the plan driven by either change to load requirements, resource capability or resource unforced capacity could impact costs, and potentially drive deficiencies in FRR Plans.

Q. PLEASE EXPLAIN THE RECENT CHANGES TO THE CAPACITY MARKET CONSTRUCT THAT PJM HAS IMPLEMENTED.

A. In a stated effort to improve the reliability of generating resources in the PJM footprint, PJM has redesigned the RPM construct with the newly coined "Capacity Performance" construct. In doing so, PJM is redefining its capacity products and proposing new performance-based incentives and assessments for non-performance. With Capacity Performance, PJM is adopting a "no-excuses" policy to improve reliability.[2] Specifically, PJM established two classes of capacity, "Capacity Performance" Capacity and, for a limited transitional period, "Base Capacity." Also during the transitional period, the current annual capacity product will continue to exist for FRR participants.

[2] *See e.g.,* PJM Press release, May 24, 2016; describing Capacity Performance "the new no excuses" standard. *Available at* http://www.pjm.com/~/media/about-pjm/newsroom/2016-releases/20160524-rpm-auction-results-for-2019-20-news-release.ashx (Last visited August 15, 2017).

Q. WHAT IS THE DISTINCTION THAT PJM HAS CREATED FOR CAPACITY PERFORMANCE RESOURCES VERSUS THE PRE-CAPACITY PERFORMANCE ANNUAL CAPACITY PRODUCT?

A. Complying capacity performance resources must be capable of sustained, predictable operation that provides energy and reserves during performance assessment hours throughout the Delivery Year. Performance assessment hours will be determined in real-time based on system conditions. They are not pre-determined, but are anticipated to occur during seasonal peak periods. Capacity performance resources are subject to non-performance assessments during emergency conditions throughout the entire Delivery Year. Base Capacity resources are required to meet the Capacity Performance standard from June through September. Base Capacity will no longer be a Capacity Market product after the transition period. Capacity Performance resources will be required to be available to PJM during periods of high load demand or system emergency, or face substantial non-performance assessments. Conversely, over-performance will be rewarded with performance-based bonuses.

Q. WHEN WILL THE CAPACITY PERFORMANCE MODEL BECOME FULLY IMPLEMENTED IN PJM?

A. In this new construct, PJM established the goal of transitioning all capacity in the PJM footprint to Capacity Performance by the 2020-2021 Delivery Year. In other words, by June 1, 2020, all capacity purchased on behalf of load through RPM or eligible for inclusion in FRR capacity plans must meet the Capacity Performance criteria.

When PJM achieves full transition to Capacity Performance for the 2020-2021 Delivery Year, every resource in the PJM footprint that is not on a PJM-approved planned outage will be obligated to be available for PJM dispatch. The obligation extends during any hour that PJM determines there to be a compliance hour throughout the entire delivery year. Compliance hours are generally set during periods of capacity or operational stress on the PJM system; and are expected by PJM to average approximately thirty hours per year over time.

Q. WHEN DID THE CAPACITY PERFORMANCE RULES GO INTO EFFECT?

A. PJM described a transitional period to achieve 100 percent Capacity Performance over four years, some years for which it had already conducted the three-year forward base auctions under the old construct. PJM has conducted transitional auctions at increasing percentages of Capacity Performance for the 2016-2017 Delivery Year through the 2019-2020 Delivery Years. Generation included in FRR Plans must eventually meet Capacity Performance requirements, and be eligible for the same performance bonuses and subject to the same non-performance assessments. FERC granted a limited Capacity Performance transition period for FRR entities like Duke Energy Kentucky that includes an exemption and step-up towards 100 percent Capacity Performance compliance for all FRR Plan resources in the 2018-2019 Delivery Year. Following the transitional percentages applied to the general market, Duke Energy Kentucky has since filed a preliminary FRR Plan for the 2019-2020 Delivery Year that includes 80 percent of its obligation as Capacity Performance capacity. The preliminary FRR Plan that

Duke Energy Kentucky filed this year, for the 2020-2021 Delivery Year required 100 percent Capacity Performance capacity.

Q. HOW WOULD YOU CLASSIFY THE CURRENT DUKE ENERGY KENTUCKY RESOURCES IN TERMS OF PJM CAPACITY PERFORMANCE COMPLIANCE AND RESPONSE?

A. PJM Capacity Performance compliance does not have a strict or bright line set of guidelines to determine whether or not it complies. The best a utility can do is manage the risks and make appropriate and prudent investments to maintain and if possible, enhance the reliability of its assets to reduce the likelihood of the asset not being able to perform when called upon during a PJM-determined event. That said, there are some minimum strategies that Duke Energy Kentucky can take in terms of ensuring there is a reliable source of fuel, and maintaining regular and proactive maintenance schedules and activities.

In my opinion, East Bend meets the minimum requirements of a Capacity Performance resource in that it is a coal-fired facility that maintains a significant reserve of fuel stored on-site. The Company is taking proactive steps to invest in the maintenance of East Bend through "asset hardening" strategies designed to reduce the possibility and likelihood of forced outages.

In my opinion, the Woodsdale facility now meets minimum Capacity Performance requirements due to the Company's completion of its dual fuel system earlier this year. The Commission authorized Duke Energy Kentucky's construction of a new dual fuel oil system for Woodsdale in Case No. 2017-

00186. The Company completed the construction and successfully tested the system in May 2019.

Q. PLEASE EXPLAIN POTENTIAL IMPACTS TO THE COMPANY AND CUSTOMERS OF CAPACITY PERFORMANCE.

A. The generation assets that the Company has invested in are sound and dependable. Duke Energy Kentucky continues to invest in and maintain these assets so that they remain reliable resources and continue to provide benefits to Duke Energy Kentucky's customers. These investments will include capital expenditures to ensure generation unit availability, as well as potential upgrades at generation stations designed to mitigate, to the greatest extent possible, exposure to the significant assessments for non-performance. Other anticipated responses to Capacity Performance risks could include the onsite maintenance of critical long lead time replacement part inventories that could reduce exposure to prolonged outages during periods where PJM is likely to initiate a Capacity Performance event.

Q. SINCE INTRODUCTION OF THE CAPACITY PERFORMANCE CONSTRUCT, HAVE THERE BEEN ANY CAPACITY PERFORMANCE ASSESMENT HOURS?

A. No. To date there have been no system wide Capacity Performance Hours called by PJM that resulted in assessments or bonuses.

Q. DO YOU BELIEVE THE CHANGES THAT PJM HAS MADE ARE BENEFICIAL TO DUKE ENERGY KENTUCKY AND ITS CUSTOMERS?

A. PJM has recognized a reliability issue in its footprint, and is acting in good faith to improve reliability of electric supply. The Capacity Performance changes are intended to incentivize investment in generating resources through enhancing the value of capacity meeting the performance guidelines and through the implementation of severe consequences for non-performance. To the extent that these changes improve reliability and cost efficiency in the PJM footprint, Duke Energy Kentucky's customers certainly benefit.

Q. PLEASE DESCRIBE ANY CHANGES TO THE WHOLESALE ELECTRIC POWER MARKETS THAT ARE ANTICIPATED TO OCCUR WITHIN THE NEXT TWO YEARS THAT COULD AFFECT DUKE ENERGY KENTUCKY'S POWER PROCUREMENT PRACTICES.

A. From a macro level perspective, the Company believes that the energy and electricity sector continues to go through an extraordinary period of change. This change is primarily driven by shifts in load growth patterns, commodity price relationships, the move towards sustainable generation, and increasing regulatory uncertainty. Continued low price natural gas is driving a transition in the traditional concept of "base load generation." As coal-fired generation continues to retire, the natural gas and intermittent resources connecting to the grid, both in front of and behind the meter, drive potential impacts on how grid operators will reliably meet demands, and the investments that will be required in energy resources and grid infrastructure and modernization. It remains to be seen what extent the current federal administration will have on the arc of environmental regulation; but that uncertainty itself will be a challenge to utilities such as Duke Energy Kentucky.

Additionally, as states address individual public policies regarding renewable and carbon free generation outside of the current capacity market design, it is expected that PJM's capacity markets will continue to evolve. Currently, PJM is awaiting an order from FERC regarding the structure and administration of its capacity market that could potentially have a significant impact on how it participates in the capacity, and if remaining an FRR entity is in the best interests of Customers. Duke Energy Kentucky continues to monitor these changes and will react accordingly.

The Company believes that the PJM energy markets will continue to function as they do today; however, wholesale energy and capacity price volatility will likely experience upward pressure. Drivers behind this increased volatility include pricing impacts from new environmental regulations as they become effective, trends towards a more renewable and efficient generation mix, and structural market changes implemented by PJM.

Q. CONSIDERING THE CHANGES IN THE WHOLESALE PJM MARKETS, INCLUDING BOTH POTENTIAL RISKS AND REWARDS, DO YOU BELIEVE DUKE ENERGY KENTUCKY'S CUSTOMERS STILL BENEFIT FROM THE COMPANY'S MEMBERSHIP IN PJM?

A. Yes. Duke Energy Kentucky's customers benefit significantly from PJM's centrally dispatched RTO construct. PJM dispatches generation in broad consideration of total RTO cost minimization, the benefits of which are directly passed to customers in the form of energy alternatives to owned generation. The approximately 180,000 MWs of generating capacity in PJM's footprint provides a significant benefit in terms of reliability and provides Duke Energy Kentucky with access to the most efficient generation providing energy. Further, these markets maximize the opportunity for non-native sales from the Company's generation, the majority proceeds of which flow back to Duke Energy Kentucky's customers through a credit on their bills. PJM's focus is on maintaining and improving reliability across its entire system, which directly translates to more efficient and reliable access to electric resources to serve Duke Energy Kentucky's customers.

IV. INFORMATION SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(7)(h)(7).

A. FR 16(7)(h)(7) provides Duke Energy Kentucky's generation mix, which for the test year is projected to be approximately 99 percent coal and 1 percent gas/oil.

Q. DID YOU PROVIDE ANY INFORMATION TO MR. JACOBI FOR HIS USE IN DEVELOPING THE FORECASTED FINANCIAL DATA?

A. Yes. I supplied Mr. Jacobi with the following information for the forecasted portion of the base period, consisting of the six months ending November 30, 2019, and for the forecasted test period, consisting of the twelve months ending March 31, 2021.

I provided Mr. Jacobi with certain production costs and revenues such as fuel costs, emission allowances costs and purchased power costs, and revenue derived from off-system sales, after applying the off-system sales sharing mechanism.

I also provided Mr. Jacobi with the projected account balances, for his use in preparing the balance sheet, and for the forecasted test period for the following items: emission allowances, coal, oil, gas and materials and supplies. I obtained this information from historic trends and adjustments for expected changes forecasted within the GenTrader® Model run.

V. CONCLUSION

Q. WAS FR 16(7)(h)(7), THE INFORMATION SUPPLIED TO MR. JACOBI PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, John A. Verderame Managing Director, Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

John A. Verderame Affiant

Subscribed and sworn to before me by John A. Verderame on this 9th day of August, 2019.

NOTARY PUBLIC

My Commission Expires:

MARY B VICKNAIR
NOTARY PUBLIC
Davie County
North Carolina
My Commission Expires Sept. 21, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

DIRECT TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 3, 2019

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr. and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director of Rates and Regulatory Strategy for Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant, focusing principally on utility rate matters. I was hired by Duke Energy (then Cinergy Services, Inc.), in 1998, as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to the position of Director - Rates. On December 1, 2009, I took the position of General Manager and Vice President of

Rates, Ohio and Kentucky. On July 3, 2012, as a result of the merger between Duke Energy and Progress Energy Corp., my title changed to Director of Rates and Regulatory Strategy for Ohio and Kentucky.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF RATES AND REGULATORY STRATEGY FOR OHIO AND KENTUCKY.

A. As Director of Rates and Regulatory Strategy for Ohio and Kentucky, I am responsible for all state and federal rate matters involving Duke Energy Kentucky and its parent, Duke Energy Ohio, Inc.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I have previously testified in several cases before the Kentucky Public Service Commission (Commission) and other regulatory commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. On behalf of Duke Energy Kentucky, I provide some background for its request to increase base electric revenues and the drivers behind the Company's application. I will support the Company's proposal to use rate base for calculating its return requirement rather than capitalization. I will also provide testimony supporting the Company's proposals relating to amortizing existing accounting deferrals previously approved by the Commission and the need for additional deferrals. I will support a proposal to modify the Company's fuel adjustment clause calculation in order to mitigate volatility the current methodology can create in customers' rates. I then discuss the Company's compliance with Commission directives from prior cases. I support the reasonableness of the Company's proposed rate increase and sponsor Filing Requirement (FR) 16(1)(b)(1) and FR 16(9) to comply with the Commission's filing requirements.

II. BACKGROUND AND BASIS FOR REQUEST

Q. WHEN DID THE COMMISSION APPROVE DUKE ENERGY KENTUCKY'S CURRENT ELECTRIC DISTRIBUTION RATES?

A. The Company's current base rates for electric service were approved by the Commission on April 13, 2018, in Case No. 2017-00321 (2017 Rate Case). The test period in that proceeding was the twelve months ended March 31, 2019, and the rate base and capitalization used in that case was the thirteen-month average from March 31, 2018, through March 31, 2019. The current rates went into effect on May 1, 2018. The Attorney General and the Company filed rehearing requests related to the initial order and the Commission issued an Order on Rehearing on October 2, 2018, which resulted in slight adjustments to the rates approved in the April 13, 2018, Order.

The last rate case was significant in that it was the first time the Company sought an increase in base rates in over ten years. In its 2017 Rate Case, the Company sought an increase of approximately $48.6 million but ultimately received an increase of $8.8 million (as approved in the October 2, 2018, Rehearing Order). The most significant factor reducing the amount of the Company's proposed increase in that case was the Tax Cuts and Jobs Act of 2017 (TCJA), which allowed the Company to significantly reduce its revenue requirement due to a reduction in the federal income tax rate and to reflect the refund, over time, of excess accumulated deferred income taxes (EDITs) that were created as a result of the TCJA.

Q. HAS THERE BEEN ANY CHANGE TO THE COMPANY'S GENERATION PORTFOLIO SINCE THE LAST RATE CASE?

A. There have been no major changes to the Company's generation portfolio since the Company's last electric rate case although it is worth noting that a major project to provide dual fuel capability at the Woodsdale Station has been completed and is in service.[1]

Q. WHAT TEST PERIOD IS DUKE ENERGY KENTUCKY USING TO CALCULATE ITS REVENUE REQUIREMENT?

A. The Company's Application in this case requests an increase in overall electric revenues based on a forecasted test period, namely, the twelve-month period beginning April 1, 2020, through March 31, 2021.

Q. WHY IS DUKE ENERGY KENTUCKY FILING A RATE CASE AT THIS TIME?

A. For the forecasted test period, the Company is projecting that the earned return on its investment in the electric system is not providing a fair and reasonable compensation to its investors.

Since the time of the last base rate case, the Company has continued making significant investment in its electric utility infrastructure. Gross utility plant in the 2017 Rate Case was approximately $1.730 billion (as approved by the

[1] *In the Matter of the Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity for Construction of a Number 2 Distillate Fuel Oil System at the Company's Woodsdale Natural Gas-Fired Generating Station,* Case No. 2017-00186 (Ky. P.S.C. Dec. 21, 2017)

Commission in its Rehearing Order[2]) based on the thirteen-month average from March 31, 2018, through March 31, 2019. The thirteen-month average of gross plant in this forecasted test period for this case is $1.949 billion, an increase of approximately $219 million in gross utility plant. The depreciation, property taxes, and return on this increased investment are the principal drivers of the need for new rates. Importantly, the Company continues to diligently control its operation and maintenance (O&M) as evidenced by the fact that over the last ten years, O&M expenses excluding production and PJM-related costs, has increased at a rate well below the inflation[3]. This effort to control costs through efficiency and productivity gains contributes to Duke Energy Kentucky being able to provide its customers with rates that are among the lowest in the Commonwealth and in the country.

Q. HAS THE TAX CUTS AND JOBS ACT OF 2017 CONTRIBUTED TO THE GROWTH IN RATE BASE?

A. Yes. The Tax Cuts and Jobs Act of 2017 (TCJA) reduced the federal income tax (FIT) rate from 35 percent to 21 percent beginning January 1, 2018, and that does benefit customers by reducing federal income tax expense included in the Company's revenue requirement. The TCJA however, has other impacts on the Company's revenue requirement, including impacting and eliminating other benefits that existed prior to the enactment of the TCJA. The reduction in the FIT rate reduces the benefit of accelerated depreciation. Also, the TCJA eliminated the benefit of bonus depreciation. This has the result of causing accumulated

[2] Order on Rehearing in Case No. 2017-00321, October 2, 2018, p. 12.
[3] Using the Consumer Price Index as Reported by the Bureau of Labor Statistics. https://www.bls.gov/cpi/home.htm.

deferred income tax (ADIT) balances to be lower than they otherwise would have been prior to the TCJA. Since ADIT is an offset included in rate base, the lower ADIT balance causes rate base to be higher.

Q. PLEASE EXPLAIN THE IMPACT OF THE TCJA ON ACCELERATED DEPRECIATION.

A. Yes. Assume, for example, that the Company's invests in a $10 million asset and that book depreciation expense is $1 million in the first year that asset is placed in service. For purposes of calculating its income tax obligation in that year, assume it is allowed to deduct $2 million for tax depreciation; so, the benefit of using accelerated depreciation for that year is $1 million multiplied by the prevailing tax rate.

Prior to the TCJA, the benefit of the accelerated depreciation would have been $350,000 ($1 million of tax depreciation minus book depreciation multiplied by 35 percent). After the TCJA, the benefit is only $210,000 because the FIT rate is now only 21 percent. This means that the Company's rate base will grow at a much faster pace as a result of the FIT change.

Q. PLEASE EXPLAIN THE IMPACT OF THE ELIMINATION OF BONUS DEPRECIATION.

A. Prior to the TCJA, the tax law allowed utilities to use an enhanced form of accelerated depreciation for tax purposes wherein a utility could deduct up to 50 percent of the value of an asset in the first year of its useful life and then transition to conventional forms of accelerated depreciation. Using the same example I described above, if the Company put a $10 million asset into service prior to the

TCJA, it could have deducted $5 million for tax depreciation compared to $1 million for book depreciation. The $4 million difference owing to the accelerated depreciation creates a $1.4 million deferred income tax that reduces the rate base upon which the Company is allowed to earn a return. The federal government is financing $1.4 million of the investment by essentially loaning the utility $1.4 million at zero interest and the $1.4 million will only be fully repaid when the asset is fully depreciated for book purposes.

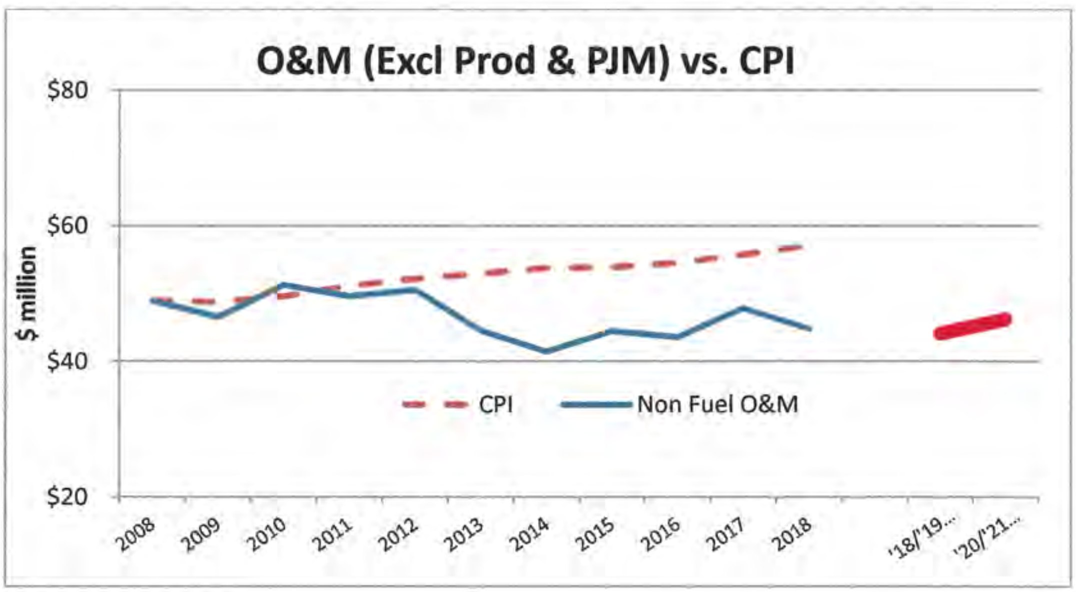
The TCJA eliminated bonus depreciation, meaning that the amount of the interest free loan from the federal government will be much lower. Put another way, the amount of financing available to the utility through the tax benefits of accelerated depreciation are reduced under the TCJA, meaning customers will end up paying more going forward than they would have prior to the enactment of the TCJA.

The combination of reducing the FIT rate and eliminating bonus depreciation means that, even if the pace of a utility's capital investment is unchanged over time, rate base will grow considerably faster because of the TCJA than it would have if the TCJA had not been enacted because the ADIT balances are smaller than they otherwise would have been prior to the TCJA.

This is a contributing factor to the growth in rate base in this proceeding and will be an increasingly significant factor in rate base growth in coming years.

Q. HAS THE COMPANY CONTINUED ITS EFFORTS TO CONTROL ITS NON-PRODUCTION O&M EXPENSE SINCE ITS LAST BASE ELECTRIC RATE CASE.

A. The chart below best demonstrates the fact that the Company has successfully controlled its non-production O&M costs over the last ten years. The bars to the left and right represent the Company's test year non-production O&M expense in its 2006 Rate Case and that projected in this current case, respectfully. The horizontal line shows the Company's non-production O&M, as reported in its FERC Form 1 Annual Reports, for each of the last ten years. As this chart shows, the Company's actual O&M expense (excluding production expenses and PJM-related costs) has remained relatively flat for the last decade and well below inflation. The chart also shows that test year O&M has remained flat as well.



Q. HAS LOAD GROWTH OFFSET THE NEED FOR THE PROPOSED INCREASE?

A. No. Although the Company continues to add customers and experiences localized load growth in specific areas, overall sales have remained essentially flat due to energy efficiency and because customers are increasingly sophisticated and mindful about controlling their energy consumption. Total retail sales for the test period in the last rate case were 4,087,791 MWh. Total sales for the forecasted test period in this proceeding are projected to be lower at 4,045,004 MWh. Inasmuch as the Company's customer charge is relatively low, particularly for residential customers[4], the growth in customer count has not been enough to offset the factors reducing customers' average usage.

Q. IS THE COST OF CAPITAL CONTRIBUTING TO OVERALL INCREASE?

A. No. Actually, since the time of the last rate case, the cost of capital has decreased. Although the return on equity of 9.80 percent being proposed in this case is slightly higher than the 9.725 percent approved in the most recent electric base rate case, the cost of debt has decreased by more over that same period. The weighted-average interest rate on long-term debt, as approved by the Commission in Case No. 2017-00321, was 4.243 percent. For the forecasted test period in this application, the long-term debt rate has fallen to 4.073 percent. Interest expense on short-term debt is also lower. Overall, the Company's weighted-average cost of capital proposed in this case is 6.711 percent compared to 6.830 percent approved by the Commission in the last electric base rate case. The significance of the change in cost of capital is that, although the Company's investment has grown since the time of the last rate case, the cost of capital related to the

[4] Duke Energy Kentucky's customer charge for residential customers is significantly lower than any major electric utility in the state.

investment has offset a significant portion of the cost of that investment.

Q. PLEASE DESCRIBE HOW THE COMPANY'S REQUESTED INCREASE IN BASE RATES WILL IMPACT CUSTOMERS' BILLS?

A. The Company's proposed overall revenue requirement is an increase of approximately 12.57 percent over current total retail revenue.[5] As discussed in testimony of Company witness James E. Ziolkowski, Duke Energy Kentucky is proposing to allocate the overall revenue requirement so that existing subsidies and excesses between rate classes are not exacerbated and, even reduced where possible. As a result of the cost of service study, the allocation of the proposed revenue requirement is such that residential customers will see an approximate 16.33 percent increase in their overall bills. Non-residential customers will see an approximate 10.11 percent increase on their bills. And, lighting customers will see an approximate 10.73 percent increase on their bills.

Q. WILL DUKE ENERGY KENTUCKY'S RATES FOR ELECTRIC SERVICE REMAIN COMPETITIVE?

A. Yes. From the most recent report from the EEI Typical Bills and Average Rate Report Winter 2019 (EEI Report), the bills for residential customers using 1,000 kWh per month, effective January 1, 2019, were $128.56 for Kentucky Power, $99.71 for Kentucky Utilities (KU), and $105.86 for Louisville Gas & Electric (LG&E). Assuming the Commission approves the Company's request in this proceeding, the bill for a Duke Energy Kentucky residential customer will be $112.08,[6] higher than KU and LG&E but lower than Kentucky Power. The

[5] *See* Schedule M, page 1 of 1, line 28.
[6] *See* Schedule N, page 1 of 5, line 6.

proposed residential bill for this customer is significantly below the national average of $138.58, per the EEI Report.

The proposed rates also result in a similar competitive position for commercial and industrial customers relative to other Kentucky investor-owned electric companies and relative to the national average.

III. ADDITIONAL RELIEF REQUESTED

A. ESTABLISHING ELECTRIC BASE RATES USING RATE BASE

Q. PLEASE EXPLAIN DUKE ENERGY KENTUCKY'S USE OF RATE BASE FOR ESTABLISHING BASE RATES IN THIS PROCEEDING.

A. Rate base represents the actual value of the physical plant used to provide utility service to customers. The Commission has the option to provide its regulated utilities a return on its capitalization supporting the rate base or to simply use rate base. Numerous examples exist where the Commission has approved base rates relying on rate base. For a combination company (*i.e.*, providing both gas and electric service), like Duke Energy Kentucky, rate base is a much simpler and more straightforward approach than the return on capitalization approach. This is because the Company's overall capitalization supports both service types; so, it is necessary to estimate the capitalization assignable to either gas service or electric service. In order to develop this estimate, Duke Energy Kentucky has historically calculated relative rate base ratios to allocate capitalization (a method approved by the Commission in Duke Energy Kentucky's last electric rate case, Case No. 2017-00321). The rate base approach is easily understood and easily verifiable, rather than the complicated process to estimate capitalization. Rate base should be approximately equal to capitalization; so, the choice of using one over the other should not result in materially different results. That said, the rate base methodology is an easier and more conventional way to represent investment in utility plant that is not only accepted by this Commission, but throughout the country.

Q. IS THE USE OF RATE BASE TO ESTABLISH BASE RATES REASONABLE AND IN THE PUBLIC INTEREST?

A. Yes. Rate base is the predominant basis among most regulators in the United States for reflecting investment in equipment and facilities used to provide utility service. Rate base is calculated relying on the books and records of the utility. Duke Energy Kentucky operates an electric business and a gas business, both of which are supported by the same capitalization. Therefore, establishing rates based on capitalization requires additional estimates to determine a reasonable basis for establishing the level of capitalization to be used for setting base rates. Estimating capitalization is especially complicated where a combination utility, like Duke Energy Kentucky, does not file simultaneous or combination electric and natural gas base rate cases. Rate base is much more straightforward in that the components of rate base are mostly comprised of discrete investments in the two services that are comparatively easy to quantify.

Q. IS THERE PRECEDENT FOR USING RATE BASE INSTEAD OF CAPITALIZATION?

A. Yes. All of the major gas local distribution companies in Kentucky, except for the Louisville Gas and Electric Company (LG&E), have base rates that were established using rate base instead of capitalization. In addition, Kentucky American Water Company also uses rate base for establishing base rates.

Q. DOES THE ATTORNEY GENERAL SUPPORT THE USE OF RATE BASE?

A. In Duke Energy Kentucky's last natural gas base rate case, Case No. 2018-00261, the Attorney General's witness, Lane Kollen, supported the use of rate base as the basis for establishing the return component of a utility's revenue requirement. From the Attorney General's witness in that case:

> "*Q. Do you support the Company's proposal to use rate base in lieu of capitalization to calculate the return component of the revenue requirement?*
>
> *A. Yes. Rate base allows the Commission to more precisely determine the costs that will be allowed a rate of return and included in the revenue requirement...*"

As the Attorney General's witness notes, the use of rate base is a more precise method for measuring the Company's actual investment in facilities and equipment to provide utility service. Admittedly, this statement was made in the context of a base natural gas rate case, the same holds true for establishing rates for other types of regulated utility service, including electric rates.

B. FUEL ADJUSTMENT CLAUSE AND PROFIT SHARING MECHANISM

Q. DESCRIBE THE COMPANY'S FUEL ADJUSTMENT CLAUSE (FAC)?

A. As provided for in 807 KAR 5:056, Duke Energy Kentucky recovers its actual fuel costs attributable to serving its retail load through a combination of amounts recovered in base rates and a separate rider, namely, the fuel adjustment clause rider (Rider FAC).

Each month, the Company calculates the cost of fuel burned in its generating facilities and any energy purchased in the market attributable to its retail load. The total cost of burning fuel and purchasing energy for its retail load in that month is divided by the actual kWh sales during that same month. The result is a rate, expressed as a $/kWh rate, that is compared to the average fuel and purchased power rate included in base rates. The difference in the two rates is recovered via Rider FAC to be billed to customers in the upcoming month. The Rider FAC could be positive or negative so that the sum of the average fuel rate and purchased power rate recovered in base rates plus Rider FAC equals the actual average cost of fuel and purchased power in that month. For example, in February, the Company will calculate the cost of fuel and purchased power attributable to serving retail load in the immediately prior month, January. The total cost is then divided by sales for the same January. The average cost of fuel and purchased power for January is then compared to the average fuel and purchased power rate included in base rates, with the difference being the Rider FAC rate that will be billed to customers in March. So, if the average cost of fuel in January is $0.0030 per kWh and $0.0025 per kWh is being recovered in base rates, then the Rider FAC for March will be $0.0005 per kWh.

Q. IS THERE A TRUE-UP PROVISION IN THE RIDER FAC CALCULATION?

A. Yes. Primarily due to monthly fluctuations in billed kWh sales and changes in actual fuel and purchased power costs, it is not common that the combination of Rider FAC and the base fuel rate exactly recovers the actual cost of fuel in a month. Consequently, there is a true-up provision whereby the Rider FAC rate is adjusted to ensure that the Company recovers no more and no less than its actual cost of providing electric generation service to its retail customers.

Q. DOES RIDER FAC CREATE VOLATILITY IN DUKE ENERGY KENTUCKY'S CUSTOMER RATES?

A. Yes. The combination of Duke Energy Kentucky's limited portfolio of generating assets and the monthly fluctuations in billed sales, creates an undesirable situation where the Rider FAC can change significantly from month-to-month.

Q. EXPLAIN HOW THE GENERATION PORTFOLIO CONTRIBUTES TO THE VOLATILITY.

A. Duke Energy Kentucky is relatively small compared to other utilities and has only two major generating stations, East Bend and Woodsdale. East Bend is a roughly 600 MW single-unit coal-fired generating station that is low-cost source of energy available to the Company's retail customers. Woodsdale is a generating station made up of six roughly 80 MW combustion turbines that were designed to run only during peak times. The Woodsdale units normally rely on natural gas for generation but can run on fuel oil if natural gas supplies are constrained. The average cost of fuel to generate energy at Woodsdale is typically much higher than the cost of fuel to generate energy at East Bend and, in most hours, is also higher than the cost of energy purchased from PJM's energy market.

Because of this limited resource mix, East Bend is the principal source of generation to serve the Company's retail customers, when it is available, and is supplemented mostly with energy purchased from PJM. While the average cost of energy generated from East Bend is not particularly volatile, the cost of purchasing energy can be quite volatile. Therefore, in those months where the availability of East Bend is limited (*e.g.*, a planned outage) or when East Bend does not generate enough to meet the demand (*e.g.*, during peak load), the average cost to serve retail customers in a given month can vary significantly.

Q. HOW DOES THE TIMING OF THE RIDER FAC CALCULATION IMPACT VOLATILITY?

A. As noted above, Rider FAC is calculated by dividing the total cost of fuel and purchased power to serve native load in the prior month by the billed sales for same prior month. Whatever rate is calculated for Rider FAC is billed in the ensuing month. Seasonal changes in demand means that retail load can vary significantly from month-to-month; so, recovering a rate calculated based on a shoulder month over a billing month during the summer can produce a significant over- or under-recovery of the FAC that will, in turn, influence the Rider FAC calculation in future months.

Q. IN YOUR OPINION, DO CUSTOMERS DESIRE VOLATILITY IN THEIR RETAIL RATES?

A. In my over thirty years of utility ratemaking experience, I am not aware of any customer suggesting that volatility in their rates for electric service was a desirable feature in their utility bills. On the contrary, volatility in retail rates is more commonly the source of complaints from customers. So, to the extent that an opportunity exists to mitigate that volatility, it would certainly be appreciated by many customers. I will emphasize that this proposed change has no financial impact on the Company.

Q. WHAT IS THE COMPANY'S PROPOSAL TO MITIGATE VOLATILITY IN THE RIDER FAC RATE?

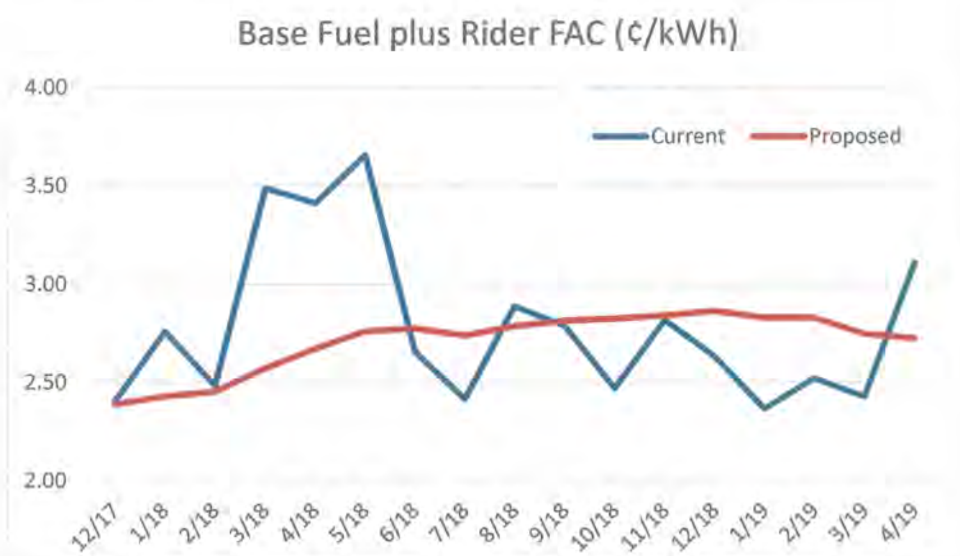
A. Duke Energy Kentucky proposes a very simple change to its Rider FAC calculation, which is to move from calculating the Rider FAC rate on a monthly basis to calculating the rate on a rolling twelve-month average basis. In Attachment WDW-1, I provide a revised set of schedules for Rider FAC reflecting the changes that would be necessary to make the calculation a rolling twelve-month average.

Q. DOES THE COMPANY REQUIRE ANY ADDITIONAL ACCOUNTING AUTHORITY FROM THE COMMISSION RELATED TO THIS PROPOSAL?

A. No. Although the use of a rolling twelve-month average may increase the magnitude of deferrals for over- or under-recovery of Rider FAC, the Company would continue the same deferral accounting for Rider FAC as is currently in effect. The Company is not requesting any waivers to accomplish this change, which will benefit customers.

Q. DO YOU HAVE AN ILLUSTRATION OF HOW THE COMPANY'S PROPOSAL WILL IMPACT VOLATILITY?

A. Simply reviewing recent Rider FAC filings provides an illustration of the how using a twelve-month rolling average to calculate Rider FAC smooths out the volatility currently evident in the monthly Rider FAC calculation.



As can be seen in this chart, the overall fuel rate (base fuel plus Rider FAC) when Rider FAC is calculated on a monthly basis can vary quite a bit. In this example, customer rates increased from February 2018 to April 2019 by about 1 cent/kWh, which, for a typical residential customer using 1,000 kWh in a month, translates to a $10 swing in that customer's bill. And, in the same chart, the Rider FAC rate goes down by over 1 cent/kWh; so, the customer will see another roughly $10 swing in the monthly bill. If the Rider FAC had been calculated on a rolling twelve-month average, the customers would have seen very little change in the average rate and, consequently, little impact on their monthly bill due to fuel costs. The Company is no better off or worse off but customers benefit from avoiding what can be unpleasant surprises in their monthly bills.

Q. WILL THIS CHANGE IMPACT THE COMMISSION'S CURRENT SIX-MONTH OR TWO-YEAR FAC REVIEW PROCESS?

A. No. The Commission will continue to have its existing authority and process to examine the Company's fuel procurement and FAC rate calculations.

Q. DOES THE COMPANY BENEFIT FROM THIS?

A. There would be no economic benefit and no economic harm to the Company from making this change. The only benefit to the Company would be from improving customer satisfaction and reducing customer complaints about volatility in its electric rates.

Q. ARE THERE ANY OTHER CHANGES BEING PROPOSED TO THE CURRENT RIDER FAC OR TO THE COMPANY'S PROFIT SHARING MECHANISM.

A. The only change to either of these riders is to include a provision to flow through the benefits derived from the Company's proposed electric vehicle (EV) pilot. Company witness Sarah E. Lawler describes how the Company is proposing to modify its Profit Sharing Mechanism (Rider PSM) to flow through to customers the benefits derived from its deployment of EVC stations.

Although not a change to the current mechanisms, Company witness Mr. Zachary Kuznar notes that any benefits derived from selling ancillary services derived from its proposed battery storage pilot into PJM's wholesale market would be credited back to customers via the Company's rider mechanisms. Because there is a fuel and non-fuel component to these ancillary revenues, the revenues would flow through to customers via the FAC and PSM, respectively.

IV. PREVIOUSLY APPROVED ACCOUNTING DEFERRALS

Q. WILL YOU SUMMARIZE THE ACCOUNTING DEFERRALS WHICH DUKE ENERGY KENTUCKY IS CURRENTLY RECOVERING IN BASE RATES?

A. Table 1 provides a summary of all of the regulatory assets that are being depreciated pursuant to the Commission's approval in the most recent electric base rate case. The table includes the total amount of the deferral and the number of years the Commission approved for amortization of each regulatory asset. approved in prior cases.

Description	Balance as of 3/31/18	Amortization Period (years)
Rate Case Expense	$657,434	5
AMI Opt Out	$263,029	5
East Bend Depreciation	$11,529,520	23.5
East Bend O&M[(a)]	$36,540,465	10
Storm Cost	$4,912,800	5
Carbon Management Research	$2,000,000	10
AMI Meter Change-Out	$6,958,958	15
[(a)] Includes a carrying cost at the long-term debt rate.		

Q. DID THE COMMISSION AUTHORIZE ADDITIONAL REGULATORY ACCOUNTING IN THE PRIOR CASE?

Q. Yes. Duke Energy Kentucky was authorized to begin deferring annual expenses for planned outages above or below the amount included in base rates and annual expenses for replacement power not recovered in Rider FAC, above or below an amount in base rates.

Q. IS THE COMPANY SEEKING TO AMORTIZE THE DEFERRALS FOR PLANNED OUTAGE EXPENSE OR REPLACEMENT POWER EXPENSE?

A. No. Based on the Company's experience thus far, we expect the actual expenses to be approximately equal, on average, to the amounts we are collecting in base rates. And, because the balance of these deferrals remains relatively small, the Company is not seeking to include any amortization of the balances in this proceeding. The deferrals will continue to be adjusted each year as actual expenses for these two expense categories are compared to the amounts being collected in base rates.

Q. HAS THE COMPANY INCLUDED AMORTIZATION EXPENSE FOR ANY OTHER DEFERRALS IN ITS FORECASTED TEST PERIOD REVENUE REQUIREMENT?

A. Yes. First, the Company is seeking to create a regulatory asset for the cost associated with developing, presenting, and litigating this base rate case. Following precedent established in prior cases, the Company is seeking a five-year amortization period for this deferral. Schedule D-2.17 reflects the impact of this adjustment.

In addition, the Company is seeking to amortize a regulatory asset related to a 2018 winter storm. On March 25, 2019, the Commission approved the Company's request to create the deferral in Case No. 2018-00416. The adjustment to revenue requirement is reflected in Schedule D-2.27.

Q. ARE THERE ANY OTHER EXPENSES FOR WHICH THE COMPANY IS SEEKING ADDITIONAL REGULATORY ACCOUNTING APPROVAL?

A. The Company is seeking approval for regulatory accounting treatment for the cost of major storms. Similar to the accounting treatment approved in the prior rate case for planned outages and replacement power, the Company is seeking authority to defer costs for major storms[7] above or below the amounts included in base rates. This would be an annual credit or debit, depending on whether actual costs for major storms over the course of a calendar year are above a base amount (a debit to the regulatory asset) or below a base amount (a credit to the regulatory asset).

Q. WHY IS THE COMPANY SEEKING DEFERRAL ACCOUNTING FOR MAJOR STORM EXPENSES?

A. The Commission has, on several occasions, approved utility requests for one-time deferrals related to the costs to recover from major storms. The Commission recognizes that the financial impact of major storms can be quite significant. As Acts of God, the frequency, magnitude, and destructiveness of major storms are very much outside the control of the utility. Duke Energy Kentucky is seeking to establish a regulatory accounting process that will mitigate the impact of major storms on its financial condition with a balanced approach that will avoid the need for separate filings each time a major storm impacts the service territory.

Q. IN WHAT WAY IS THE REGULATORY ACCOUNTING AUTHORITY BEING SOUGHT "BALANCED"?

A. Duke Energy Kentucky, like most electric utilities, includes what amounts to an

[7] The request is limited to costs involving "major" storms as defined by IEEE Standards 1366.

average expense for major storms in its test period. Some years may be uneventful, in which case, the Company's revenue requirement may include more expense for major storms than is actually spent. That would benefit the Company's shareholders. On the other hand, some years or even some individual storms may be quite impactful and may cost the utility much more than it is recovering in base rates.

Occasionally, when the cost of a storm or storms is much higher than the amount being recovered in base rates, a utility may seek approval to defer the expense.

The "balance" in the approach being proposed by the Company lies in the fact that customers will never pay more or less than the 'actual' cost of the storm restoration. The current model typically results in the utility being made whole when costs exceed base rates but the customer is not made whole when storm costs are less than the amount recovered in base rates. The proposed model remedies that imbalance.

Q. IS THERE ANY PRECEDENT FOR THAT REGULATORY ACCOUNTING MODEL?

A. Yes. It is essentially the same model that most regulated electric distribution utilities have been utilizing for several years in Ohio.

Q. IS THERE ANY OTHER REGULATORY ACCOUNTING AUTHORITY BEING SOUGHT BY THE COMPANY IN THIS CASE?

A. Yes. As mentioned above, the Company is requesting that the Commission approve a pilot program for EVC stations. Because there will be costs incurred by the Company to implement this program that are not included in the test year revenue requirement, the Company is seeking approval to defer incremental costs to implement the pilot program for recovery in a future rate case.

V. COMPLIANCE WITH COMMISSION DIRECTIVES

Q. ARE YOU FAMILIAR WITH THE VARIOUS REGULATORY COMMITMENTS AND COMMISSION DIRECTIVES IMPOSED ON DUKE ENERGY KENTUCKY AS THEY RELATE TO RETAIL RATEMAKING?

A. Yes. As part of the recent mergers with Duke Energy and Progress Energy[8] and Piedmont Corporation (Piedmont),[9] there are a few commitments made by Duke Energy Kentucky as it relates to the implications of these mergers on retail rates.

Q. PLEASE LIST THE COMMITMENTS THAT RELATE TO RATEMAKING AND COST RECOVERY AND EXPLAIN HOW THE COMPANY HAS COMPLIED WITH THESE COMMITMENTS IN THIS CASE?

A. As part of the resolution of Case No. 2011-0124, Duke Energy Kentucky made numerous commitments. I am addressing the specific commitments that touch on the Company's rate making and cost recovery:

1) Commitment 3: The payment of Progress Energy Stock shall be excluded from the books of Duke Energy Kentucky for retail ratemaking

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[8] *In the Matter of the Joint Application of Duke Energy Corporation, Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisitions Corporation, and Progress Energy Inc., for Approval of the indirect Transfer of Control of Duke Energy Kentucky, Inc.,* Case No. 2011-00124 (Ky. P.S.C. Oct. 28, 2011).
[9] *In the Matter of the Application of Duke Energy Kentucky, Inc., for a Declaratory Order,* Case No. 2015-00413 (Ky. P.S.C. March 7, 2016).

purpose. The Company has not included any such payments in the Company's test year revenue requirement.

2) Commitment No. 4: Any acquisition premium paid by Duke Energy for the Progress Energy stock shall not be pushed down to Duke Energy Kentucky. The Company has not included any such payments in its test year revenue requirement.

3) Commitment No. 5: No change in control payments shall be allocated to Duke Energy Kentucky retail rate payers. The Company has not included any such payments in its test year revenue requirement.

4) Commitment No. 14: The Commission shall have ongoing jurisdiction over the Company's capital structure, financing and cost of capital. The Company has presented its capital structure and costs of capital for the Commission's review in this proceeding.

5) Commitment No. 15: The merger will have no adverse impact on the base rates or the operation of the fuel adjustment clause, gas cost recovery and demand side management clause of Duke Energy Kentucky. There are no such adverse impacts caused by the merger.

6) Commitment No. 16: Duke Energy Kentucky will not seek a higher rate or return on equity than would have been sought if the merger transaction had not occurred. Duke Energy Kentucky presents the direct testimony of Roger A. Morin Ph.D., whose analysis supports the Company's requested return on equity.

7) Commitment No. 17: The accounting and ratemaking treatments of Duke Energy Kentucky's excess accumulated deferred income taxes (ADITs) will not be affected by the merger of Duke Energy and Progress Energy. As demonstrated by the Company's application in this proceeding, there has been no impact to the Company's excess accumulated deferred income taxes related to the merger with Progress Energy.

8) Commitment No. 22, Duke Energy Kentucky will pay dividends only out of retained earnings and to maintain a capital structure that maintains a minimum of thirty-five (35) percent equity. As demonstrated by its application, the Company has maintained an equity ratio that is greater than 35 percent equity. Further, the Company has only paid its dividends out of retained earnings.

9) Commitment No. 44, if the merger between Duke Energy and Progress Energy was not completed, Kentucky customers will not bear any costs of the failed transaction. As the Commission is aware, the merger between Duke Energy and Progress Energy was completed; so, there were no termination payments made or received. This commitment is now moot.

10) Commitment 47, Duke Energy Kentucky committed to aggressively pursue cost-effective demand-side management (DSM) and energy efficiency (EE) programs and to deploy such programs using industry best practices in Kentucky. The Company continues to evaluate and

11) Commitment 49, no costs to achieve the merger transaction will be recovered from Duke Energy Kentucky ratepayers. As evidenced by the Company's filing, no costs to achieve the merger transactions have been included in the Company's application.

In Case No. 2015-00413, related to the merger between Duke Energy and Piedmont Natural Gas Company, Duke Energy Kentucky reasserted its commitment that in future rate cases, it will not seek a higher rate of return on equity than would have been sought if the proposed acquisition of Piedmont had not occurred. In the Company's last electric base rate case, Case No. 2017-00321, the Company addressed these commitments and confirmed its compliance with same. The Company's Application includes the Direct Testimony of Dr. Roger A. Morin to support the Company's requested return on equity in this proceeding. Dr. Morin's testimony and recommended range of a reasonable return is accompanied by a thorough analysis that is not reliant upon the Company's history of mergers.

VI. REASONABLENESS OF REQUEST

Q. IS THE COMPANY'S REQUESTED RATE RELIEF REASONABLE?

A. Yes. Duke Energy Kentucky's retail electric rates are currently the lowest in the Commonwealth and among the lowest in the country. Even after the increased proposed in this Application, the Company's retail rates will continue to be very competitive with other Kentucky investor-owned utilities and much lower than the national average. That enviable position owes, in part, to the Company's focus on cost control and, in part, to the Commission's foresight in encouraging Duke Energy Kentucky to acquire its own generation near the beginning of this century. The low-cost generation acquired at that time has been a significant factor in Duke Energy Kentucky maintaining its low rates over the years.

VII. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(1)(b)(1).

A. FR 16(1)(b)(1) is Duke Energy Kentucky's statement of the reasons for the proposed increase.

Q. PLEASE DESCRIBE FR 16(9).

A. FR 16(9) is Duke Energy Kentucky's acknowledgement that it understands that its application will not be accepted for filing until it has cured any deficiencies as determined by the Commission.

VIII. CONCLUSION

Q. HAVE YOU REVIEWED DUKE ENERGY KENTUCKY'S APPLICATION IN THESE PROCEEDINGS?

A. Yes. I have also reviewed the testimony and attachments of all Company witnesses. I believe that the Company's total electric revenue requirement is properly computed, the costs of service are properly allocated to customer classes, and the rate design is equitable.

Q. DO YOU BELIEVE DUKE ENERGY KENTUCKY'S RATE REQUEST IS REASONABLE?

A. Yes.

Q. WERE ATTACHMENTS WDW-1, FR 16(1)(b)(1) AND FR 16(9) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, William Don Wathen Jr., Director of Rates & Regulatory Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen Jr., on this 30th day of August, 2019.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

Schedule 1

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average - Expense Month: **July 20XX**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ -		
2	Sales S_m (Schedule 3, Line C)	÷	-		-
3	Base Fuel Rate (F_b/S_b) per PSC Order in Case No. 2017-00005			(-)	-
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				-

Effective Date for Billing: ______________________________

Submitted by: ______________________________

Title: ______________________________

Date Submitted: ______________________________

Schedule 2

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average - Expense Month: July 20XX

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	$ -
Oil Burned	(+)	-
Gas Burned	(+)	-
Net Fuel Related RTO Billing Line Items	(-)	-
Fuel (assigned cost during Forced Outage[(a)])	(+)	-
Fuel (substitute cost during Forced Outage[(a)])	(-)	-
Sub-Total		$ -
B. Purchases		
Economy Purchases	(+)	$ -
Other Purchases	(+)	-
Other Purchases (substitute for Forced Outage[(a)])	(-)	-
Less purchases above highest cost units	(-)	-
Sub-Total		$ -
C. Non-Native Sales Fuel Costs	(-)	$ -
D. Total Fuel Costs (A + B - C)	(+)	$ - [(b)]
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ -
F. Adjustment indicating the difference in actual fuel cost for the month of June 20XX and the estimated cost orginally reported $x,xxx,xxx (actual) - $x,xxx,xxx (estimate)	(+)	$ -
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ -
H. Prior Period Correction	(+)	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ -

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.
[(b)] Estimated - to be trued up in the filing next month

Schedule 3

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average - Expense Month: July 20XX

		Kilowatt-Hours Current Month
A. Generation (Net)	(+)	-
Purchases Including Interchange-In	(+)	-
Sub-Total		-
B. Pumped Storage Energy	(+)	-
Non-Native Sales Including Interchange Out	(+)	-
System Losses [(a)]	(+)	-
Sub-Total		-
C. Total Sales (A - B)		-

Note: [(a)] Average of prior 12 months.

Schedule 4

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Twelve Month Average - Expense Month: June 20XX

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	$ -
Oil Burned	(+)	-
Gas Burned	(+)	-
Net Fuel Related RTO Billing Line Items	(-)	-
Fuel (assigned cost during Forced Outage[(a)])	(+)	-
Fuel (substitute cost during Forced Outage[(a)])	(-)	-
Sub-Total		$ -
B. Purchases		
Economy Purchases	(+)	$ -
Other Purchases	(+)	-
Other Purchases (substitute for Forced Outage[(a)])	(-)	-
Less purchases above highest cost units	(-)	-
Sub-Total		$ -
C. Non-Native Sales Fuel Costs	(-)	$ -
D. Total Fuel Costs (A + B - C)		$ -

Note: [(a)] Forced Outage as defined in 807 KAR 5:056.

Schedule 5

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Expense Month: May 20XX

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.000000
2	Retail kWh Billed at Above Rate	(x)		-
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	-
4	kWh Used to Determine Last FAC Rate Billed	(+)		-
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			-
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	-
8	Over or (Under) (Line 3 - Line 7)		$	-
9	Total Sales (Schedule 3, Line C)	(-)		-
10	Kentucky Jurisdictional Sales	(÷)		-
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			-
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	-
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	-

Schedule 6

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Twelve Month Average - Expense Month: March 20XX

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	$ -
Oil Burned	(+)	-
Gas Burned	(+)	-
Net Fuel Related RTO Billing Line Items	(-)	-
Fuel (assigned cost during Forced Outage[a])	(+)	-
Fuel (substitute cost during Forced Outage[a])	(-)	-
Sub-Total		$ -
B. Purchases		
Economy Purchases	(+)	$ -
Other Purchases	(+)	-
Other Purchases (substitute for Forced Outage[a])	(-)	-
Less purchases above highest cost units	(-)	-
Sub-Total		$ -
C. Non-Native Sales Fuel Costs	(-)	$ -
D. Total Fuel Costs (A + B - C)		$ -
E. Total Fuel Costs Previously Reported	(-)	$ -
F. Prior Period Adjustment	(+)	$ -
G. Adjustment due to PJM Resettlements		$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

DIRECT TESTIMONY OF

DANIELLE L. WEATHERSTON

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 3, 2019

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Danielle L. Weatherston and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Manager Accounting II. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Indiana State University with a Bachelor of Science in Accounting and from Ball State University with a Master of Arts in Business Education. I am also a certified public accountant in Indiana. I have held various accounting roles at Sony Disc Manufacturing and Hill-Rom in Indiana, prior to joining Duke Energy. At Duke Energy I have worked in various groups such as corporate accounting, regulated accounting, and commercial power before accepting my current role as Manager Accounting II in Charlotte.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER ACCOUNTING II.

A. I am responsible for maintaining the books of account and reporting the financial position and the results of electric operations for Duke Energy's public utility operating companies in Ohio and Kentucky.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

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

A. My testimony in this proceeding addresses the various capital and operating expenditures and accounting adjustments to Duke Energy Kentucky's books of account in support of Duke Energy Kentucky's application in this proceeding. I discuss the accounting treatment being requested in this proceeding for two categories of regulatory assets/liabilities as I will discuss further in my testimony. I sponsor the historic data in Schedule B-8 provided in satisfaction of Filing Requirement FR 16(8)(b); and Filing Requirements FR 12(2)(i), FR 16(7)(i), FR 16(7)(k), FR 16(7)(m), FR 16(7)(n), FR 16(7)(o), FR 16(7)(p), and FR 16(7)(q). Finally, I also sponsor the historic data on Schedules I-1 through I-5 in response to FR 16(8)(i), and Schedule K in response to FR 16(8)(k).

II. OVERVIEW OF DUKE ENERGY KENTUCKY'S ACCOUNTING RECORDS

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DUKE ENERGY KENTUCKY?

A. Yes. The books of account for Duke Energy Kentucky's regulated business follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Q. ARE THE BOOKS OF ACCOUNT FOR THE ELECTRIC BUSINESS OF DUKE ENERGY KENTUCKY PREPARED AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. ARE THE CAPITAL AND OPERATING EXPENDITURES REPRESENTED ON DUKE ENERGY KENTUCKY'S BOOKS OF ACCOUNT ACCURATE AND REASONABLE?

A. Yes. Duke Energy Kentucky has various budgeting, planning, and review procedures in place to establish and monitor the capital and operating budgets, as well as actual expenditures. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly.

The system of internal accounting controls is annually reviewed, tested, and documented by Duke Energy Kentucky to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that Duke Energy Kentucky's financial statements are materially accurate.

III. ACCOUNTING TREATMENT

Q. PLEASE BRIEFLY DESCRIBE THE ACCOUNTING TREATMENT THE COMPANY IS REQUESTING IN THIS PROCEEDING.

A. As part of this proceeding, Duke Energy Kentucky is seeking Commission authorization to create a major storm deferral mechanism (asset and liability as necessary) for the differences between the actual amounts incurred for major storm restoration costs each year and the amounts established in base rates for those costs in this proceeding. The deferral mechanism proposed will allow the Company to defer the actual annual operation and maintenance (O&M) expense related to major storm restoration above or below the amount being recovered in base rates. The Company will either credit or debit the balance on an annual basis, over or under the amount in base rates for amortization in a future proceeding.

Similarly, the Company is seeking Commission authorization to create a deferral for O&M expense associated with its proposed electric vehicle (EV) program as further described by Company witness Lang Reynolds in his testimony.

In addition to the request for regulatory asset treatment for this item, Duke Energy Kentucky will continue recording deferrals, per normal regulatory accounting standards, for previously approved deferral mechanisms (*e.g.*, replacement power and generation outage expense[1]), as well as its various riders that are subject to being trued-up. Over- or under-recovery of costs are flowed through riders such as the fuel adjustment clause, environmental surcharge, demand-side management and the profit sharing mechanism and, therefore, the Company records the amounts to be trued-up in future periods as regulatory assets or regulatory liabilities.

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[1] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for: 1) 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 (Ky. P.S.C. Order pp. 16, 20) (April 13, 2018).

Q. WHY IS IT APPROPRIATE TO CREATE A REGULATORY ASSET/LIABILITY FOR MAJOR STORMS?

A. The Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the costs.

The costs for which the Company is seeking to create the regulatory deferral for major storm O&M expenses represent incremental costs or savings compared to normalized or expected levels, and as such they effectively constitute extraordinary non-recurring expenses (or savings) which could not have reasonably been anticipated or included in the utility's planning. The actual costs of these items are unable to be planned or anticipated. Major storms cannot be predicted and are outside the Company's control. The Company has previously sought Commission authorization for deferrals when these major storm events occur. The most recent such event involved an unanticipated ice storm that occurred in November 2018.[2]

The Company's forecasted test year budget for major storms has been adjusted to reflect a representative (*i.e.,* average) level of expense. Deferral mechanisms balance the need for protecting customers from over paying for these

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[2] *In the Matter of the Application of Duke Energy Kentucky, Inc for an Order Approving the Establishment of a Regulatory Asset*, Case No. 2018-00416 (Ky. P.S.C. Order) (March 25, 2019).

costs when the utility's actual costs incurred are below the levels used to establish base rates, and conversely mitigate the utility's risk to financial stability and performance during years where the Company's actual costs incurred are higher than those used to establish base rates.

Creating this mechanism will alleviate the need for the Company to file and the Commission to review multiple separate deferrals that may occur throughout the year. Additionally, it will reduce the Commission's burden in reviewing concurring applications from multiple utilities when these events occur. As history demonstrates, when a severe weather event impacts Kentucky, several utilities are impacted resulting in the Commission receiving deferral requests from multiple utilities. The proposed deferral mechanism will allow the Company to just create the regulatory asset if and when a major storm expense in a calendar year exceeds what is in base rates, and also credit against base rates when such annual expense is less than what may be included in rates.

Although Duke Energy Kentucky is relatively small, the swings from year to year in the costs of major storm outages causes volatility in the Company's earnings. The proposed deferral mechanisms are designed so that, over time, the balance should approach $0, but will prevent this volatile cost item from having a significant influence on the Company's earnings.

Q. HOW WILL THIS REGULATORY ASSET/LIABILITY WORK?

A. On an annual basis, the Company will track the actual costs of major storm outages against the base rate level established in this proceeding and will either debit a regulatory asset account (Account 182.3) or credit a regulatory liability account (Account 254), for the difference between the actual costs and the amounts in base rates. The balance of the regulatory asset or liability will accrue a carrying cost at the Company's long-term debt rate approved in this proceeding. The carrying costs will apply to any credit balance (*i.e.*, amounts owed to customers) or to any debit balance (*i.e.*, amounts owed to the Company) to maintain the symmetry and ensure that neither customer nor Company is deprived of the time value of money.

This regulatory asset or liability account will continue to accumulate until the next rate case when the Company will seek to include the then existing balance for recovery or refund in new base rates. The intent with this deferral is simply to provide assurance that the Company can recover its costs and customers pay no more or no less than the actual cost incurred for costs of major storm outages.

Q. WHY IS IT APPROPRIATE TO CREATE A REGULATORY ASSET FOR THE EV PROGRAM O&M?

A. As explained by Duke Energy Kentucky witness Reynolds, the Company is proposing a process for galvanizing the development of electric vehicle charging and passing any net revenues from Company-owned charging stations back to customers through its profit sharing mechanism, Rider PSM. The regulatory asset will ensure that only the actual costs will be recovered and that the Company does not over or under recover for these costs. The O&M costs to be included relate to incentives paid to qualifying customers under the program.

Q. HOW WILL THIS REGULATORY ASSET/LIABILITY WORK?

A. On a monthly basis, O&M expense will be recorded to a regulatory asset account (Account 182.3) as incurred. The balance of the regulatory asset will accrue a carrying cost at the Company's long-term debt rate approved in this proceeding.

This regulatory asset account will continue to accumulate until the next rate case when the Company will seek to include the then existing balance for recovery or refund in new base rates.

Q. WHY IS THE INCLUSION OF CARRYING CHARGES BASED UPON THE COMPANY'S COST OF DEBT APPROPRIATE?

A. The use of carrying costs simply represents the time-value of money being deferred for future recovery/crediting to customers. The cost of debt is a reasonable rate and represents the Company's borrowing rate if it were to seek funds elsewhere. These carrying costs will work both ways in that they would accrue on both the regulatory asset as well as the liability.

Pursuant to KRS 278.220, the system of accounts established by the Commission for keeping by the Company shall conform as nearly as practicable to the system adopted by FERC. Relevant precedent from FERC reflects the fact that jurisdictional utilities are regularly authorized to accrue a carrying charge on a regulatory asset until the regulatory asset is included in rate base. Such an accrual is appropriate because the subject costs are necessarily incurred by the Company. Guidance from FERC and prudent accounting principles support the inclusion of carrying costs as part of the subject regulatory asset until the Commission determines whether the deferred costs are recoverable.

Q. PLEASE DESCRIBE THE ACCOUNTING/JOURNAL ENTRIES THAT WILL BE USED TO CREATE THESE DEFERRALS.

A. For the major storm deferral, if the actual costs are higher than those in base rates, the Company would debit a regulatory asset and credit various O&M accounts, for example:

Debit Account 182.3

Credit Account 5XX

If however, the actual costs are lower than those recovered in base rates, the Company would debit expense and credit a regulatory liability, for example:

Debit Account 45XX

Credit Account 254

Q. YOU MENTIONED THAT THE COMPANY IS CONTINUING ITS PREVIOUSLY APPROVED DEFERRAL MECHANISMS FOR PLANNED OUTAGES AND PURCHASED POWER EXPENSE IN THIS PROCEEDING. WHAT ARE THE BALANCES OF THESE ASSETS?

A. The balance as of June 30, 2019 related to the planned outages is a net asset of $2,066,087. The June 30, 2019 balance related to the deferral of purchased power expense is a net asset of $325,322. As provided to me by Company witness Jacobi, the balance in the deferred planned outage account is projected to be a net liability of $642,370 as of March 31, 2020. The balance in the deferred purchase power account is projected to be a net asset of $342,432 as of March 31, 2020.

Q. IS DUKE ENERGY KENTUCKY PROPOSING TO ADJUST THE AMOUNTS IN BASE RATES FOR EITHER OF THESE TWO MECHANISMS FOR PURPOSES OF MEASURING INCREMENTAL EXPENSE?

A. No.

Q. IS DUKE ENERGY PROPOSING ANY AMORTIZATION PERIOD FOR THESE BALANCES IN THIS CASE?

A. No.

IV. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE B-8.

A. Schedule B-8 contains the Comparative Balance Sheets for Duke Energy Kentucky for the most recent five calendar years, the base period and the forecasted period.

Q. PLEASE DESCRIBE FR 12(2)(i).

A. FR 12(2)(i) consists of Duke Energy Kentucky's detailed income statement and balance sheet for the period ended June 30, 2019.

Q. PLEASE DESCRIBE FR 16(7)(i).

A. FR 16(7)(i) consists of the Company's most recent Federal Energy Regulatory Commission (FERC) audit report, reporting the results of the Company's last FERC audit.

Q. PLEASE DESCRIBE FR 16(7)(k).

A. FR 16(7)(k) consists of Duke Energy Kentucky's most recent FERC Form 1 and FERC Form 2.

Q. PLEASE DESCRIBE FR 16(7)(m).

A. FR 16(7)(m) consists of Duke Energy Kentucky's current chart of accounts.

Q. PLEASE DESCRIBE FR 16(7)(n).

A. FR 16(7)(n) consists of the latest twelve months of the monthly management reports providing financial results of the Company's operations in comparison to the forecast.

Q. PLEASE DESCRIBE FR 16(7)(o).

A. FR 16(7)(o) consists of management's monthly budget variance reports for Duke Energy Kentucky electric operations.

Q. PLEASE DESCRIBE FR 16(7)(p).

A. FR 16(7)(p) consists of Duke Energy Kentucky's most recent Form 10-K and Form 8-K as well as those forms for the last two years. Additionally, the Company is submitting copies of its Form 10-Qs that were filed during the past six quarters.

Q. PLEASE DESCRIBE FR 16(7)(q).

A. FR 16(7)(q) consists of the independent auditor's annual opinion report for Duke Energy Kentucky. The auditor did not note any material weaknesses in internal controls.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN RESPONSE TO FR 16(8)(i), SCHEDULES I-1 THROUGH I-5.

A. Schedule I-1 contains comparative income statements for the Company. Schedules I-2.1 through I-5 contains comparative revenue and sales statistical information as required by the Commission's filing requirements. I support the historic information contained on these schedules.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN RESPONSE TO FR 16(8)(k), THE "K" SCHEDULES.

A. The information I support in response to FR 16(8)(k) consists of the Consolidated Condensed Income Statement for Duke Energy Kentucky. I provided this information to Mr. Jacobi for his use in preparation of the forecast.

V. CONCLUSION

Q. WAS THE INFORMATION YOU SPONSORED IN SCHEDULES B-8, I-1, I-2.1, I-3, I-4, I-5 AND K AS WELL AS FR 12(2)(i), FR 16(7)(i), FR 16(7)(k), FR 16(7)(m), FR 16(7)(n), FR 16(7)(o), FR 16(7)(p), FR 16(7)(q), FR16(8)(i), AND FR 16(8)(k) PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. IS THE INFORMATION YOU SPONSORED IN THOSE SCHEDULES AND FILING REQUIREMENTS ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Danielle L. Weatherston, Manager Accounting II, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Danielle L. Weatherston

Danielle L. Weatherston, Affiant

Subscribed and sworn to before me by Danielle L. Weatherston on this 9th day of August, 2019.

GEORGIANNA A ANDERSON NOTARY PUBLIC MECKLENBURG COUNTY, NC

NOTARY PUBLIC

My Commission Expires: August 18, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

DIRECT TESTIMONY OF

JAMES E. ZIOLKOWSKI

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 3, 2019

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James E. Ziolkowski, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Rates & Regulatory Planning. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from the U.S. Naval Academy in 1979 and a Master of Business Administration degree from Miami University in 1988. I am also a licensed Professional Engineer in the state of Ohio. I received certification as a Chartered Industrial Gas Consultant in 1994 from the Institute of Gas Technology and the American Gas Association. I have attended the EUCI Cost of Service seminar.

After graduating from the Naval Academy, I attended the Naval Nuclear Power School and other follow-on schools. I served as a nuclear-trained officer on various ships in the U.S. Navy through 1986. From 1988 through 1990, I worked for Mobil Oil Corporation as a Marine Marketing Representative in the New York City area.

I joined The Cincinnati Gas & Electric Company n/k/a Duke Energy Ohio, Inc., (Duke Energy Ohio) in 1990 as a Product Applications Engineer, in which capacity I designed and managed some of Duke Energy Ohio's demand side management programs, including Energy Audits and Interruptible Rates. From 1996 until 1998, I was an Account Engineer and worked with large customers to resolve various service-related issues, particularly in the areas of billing, metering, and demand management. In 1998, I joined the Rate Department, where I focused on rate design and tariff administration. I was appointed to my current position in January 2014.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR RATES & REGULATORY PLANNING.

A. As Director Rates & Regulatory Planning, I am responsible for cost of service studies, tariff administration, billing, and revenue reporting issues in Kentucky and Ohio. I also prepare filings to modify charges and terms in the retail tariffs of both Duke Energy Kentucky and Duke Energy Ohio, and I develop rates for new services. During major rate cases, I help with the design of the new base rates. Additionally, I frequently work with Duke Energy Kentucky's and Duke Energy Ohio's customer contact and billing personnel to answer rate-related questions, and to apply the retail tariffs to specific situations. Occasionally, I meet with customers and Company representatives to explain rates or provide rate training. I also prepare reports that are required by regulatory authorities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

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

A. I sponsor Schedules B-7, B-7.1, B-7.2, D-3, D-4, and D-5 in response to Filing Requirement FR 16(8)(b) and FR 16(8)(d), respectively. I also support the electric cost of service studies identified in response to Filing Requirement FR 16(7)(v).

II. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES B-7 AND D-3.

A. These schedules report the allocation factors used to determine the jurisdictional percentages of electric plant, expenses, *etc.*, necessary to allocate the amount of the proposed new electric rates between jurisdictional and non-jurisdictional customers. These schedules indicate that 100 percent of the costs are jurisdictional, because Duke Energy Kentucky does not provide service to any non-jurisdictional electric customers.

Q. PLEASE DESCRIBE SCHEDULES B-7.1 AND D-4.

A. These schedules are the support for Schedules B-7 and D-3 described above. They provide the basis for the actual jurisdictional allocation factors.

Q. PLEASE DESCRIBE SCHEDULES B-7.2 AND D-5.

A. These schedules explain changes made to the jurisdictional allocation from the Company's prior electric rate proceeding in Case No. 2017-00321.

Q. PLEASE DESCRIBE FR 16(7)(v).

A. FR16(7)(v) contains 25 schedules: Schedules FR16(7)(v)-1 through FR 16(7)(v)-25 which represent the fully allocated, embedded cost of service study by rate class. I discuss these filing requirements in greater detail in my testimony below.

III. COST OF SERVICE STUDIES

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY?

A. A cost-of-service study is an analytical tool used in traditional utility rate design to allocate costs to different classes of customers. When the process of preparing a cost-of-service study is completed, the resulting class cost-of-service study can (1) assist in determining the revenue requirement for the services offered by a utility; (2) analyze, at a very detailed level, the costs imposed on the utility's system by different classes of customers; (3) show the total costs the company incurs in serving each retail rate class, as well as the rate of return on capitalization earned from each class during the test year; and (4) establish cost responsibility that makes it possible to determine just and reasonable rates based on costs.

Q. WHAT INFORMATION DID THE COMPANY USE TO DEVELOP THE COST ALLOCATION FACTORS FOR THE COST OF SERVICE STUDIES USED IN THIS PROCEEDING?

A. The test year for this proceeding is the twelve months ending March 31, 2021, which is comprised of forecasted test period data. The development of the test year allocation factors is primarily based on historical data for the twelve months ended December 2018. Otherwise, forecasted test year information was used as appropriate. I will discuss the actual development of the various allocation factors used in this proceeding later in my testimony.

Q. HAS THE COMPANY PREPARED MULTIPLE COSTS OF SERVICE STUDIES?

A. Yes. The Company prepared three Class Cost of Service Studies that contain essentially the same data, except that different methodologies were used to develop the allocation factor for the demand component of Production-related costs. The demand allocation methods are as follows: (1) the Average of the Twelve (12) Coincident Peaks (12 CP) method; (2) the Average and Excess (A&E) method; and (3) the Production Stacking method.

Q. PLEASE DESCRIBE THE DEMAND METHODOLOGIES USED IN THESE COST OF SERVICE STUDIES.

A. The 12 CP method is designed to allocate capacity related costs to the customer classes using the system during maximum system load. The allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of what their respective loads were at other times of the day.

The A&E method, also referred to as the "used and unused capacity method," recognizes both the class average use of the system capacity and the class contribution to the capacity required to meet the maximum system load. The capacity costs are allocated in a two-part formula. Attachment JEZ-3 shows the calculation of the production allocator K201 using the A&E method.

The "class-used" capacity component is the proportion of the class's respective average hourly kilowatt-hour (kWh) sales to the total average hourly sales. The "class-unused" capacity is the class excess hourly peak demand contribution ratio, which is the difference between the class average hourly demands and the hourly class peak demands. The used and unused capacity factors for each class are combined to allocate capacity costs to the respective rate classes.

The Production Stacking method is a time-differentiated method that allocates baseload plant costs on energy (kWh) and peaker plants costs on peak demands. As shown in Attachment JEZ-4, net plant associated with the East Bend plant is allocated to each rate class based on annual kWh. Net plant associated with the Woodsdale facility is allocated to each rate class based on 12 CP. The K201 production allocator combines both allocations.

Q. DID YOU COMPARE THE CLASS DEMAND RATIOS FOR EACH OF THE DEMAND METHODOLOGIES?

A. Yes. Attachment JEZ-1 shows the demand ratios for the different methods. Attachment JEZ-2 shows the rate impacts using the different methods.

Q. BASED UPON YOUR COMPARISON OF THE 12 CP, A&E AND PRODUCTION STACKING METHODOLOGIES, WHICH DO YOU RECOMMEND THE COMMISSION APPROVE IN THIS PROCEEDING?

A. I recommend using the Average 12 CP methodology for three reasons. First, the 12 CP method is generally accepted in the utility industry and was approved by the Commission in the Company's last electric base rate case. The 12 CP demand methodology has been used in other jurisdictions including Duke Energy Ohio's and Duke Energy Indiana's rate proceedings. Second, this methodology recognizes that Duke Energy Kentucky's current generating facilities are in place precisely to meet the monthly maximum peak loads of customers. Third, there was no compelling reason to adopt a new methodology. Rate subsidies will generally occur among customer classes, regardless of the cost of service methodology used. Changing to either the A&E or Production Stacking methodology will not change this fact. The

Company believes that the use of the 12 CP methodology is the appropriate means to align capacity costs with the customer classes that are imposing the costs.

Q. PLEASE DESCRIBE THE ELECTRIC COST OF SERVICE STUDY.

A. The electric cost of service study contained in Schedules FR-16(7)(v)-1 through FR-16(7)(v)-25 is an embedded, fully allocated cost of service study by rate class for the test period ended March 31, 2021. In preparing the cost of service study, I used information provided by other Company employees. The cost of service study functionalizes, classifies, and allocates cost items such as plant investment, operating expenses, and taxes to the various customer classes and calculates the revenue responsibility of each class. Finally, the cost of service study calculates the revenue responsibility of each rate class required to generate the recommended rate of return.

Q. PLEASE DESCRIBE HOW THE COST OF SERVICE STUDY IS ORGANIZED IN SCHEDULES FR-16(7)(v)-1 THROUGH SCHEDULE FR-16(7)(v)-25.

A. The schedules provided in the cost of service study are organized as shown in the table below. The detailed calculation and derivation of the allocation factors utilized in the cost of service study are included in the workpapers filed in these proceedings.

Table 1		
Schedule	Page No.	Description
Schedule 1	1	Summary of Results
Schedule 2	2	Gross Plant in Service
Schedule 3	3	Depreciation Reserve
Schedule 4	4	Net Electric Plant in Service
Schedule 5	5	Subtractive Rate Base Adjustments
Schedule 5.1	6	Additive Rate Base Adjustments
Schedule 5.2	7	Working Capital
Schedule 6	8	O&M Expenses
Schedule 6.1	9	O&M Expenses
Schedule 7	10	Depreciation Expense
Schedule 8	11	Taxes Other Than Income Taxes
Schedule 9	12	Federal Income Tax Based on Return
Schedule 9.1	13	State Income Tax Based on Return
Schedule 10	14	Cost of Service Computation
Schedule 11	15	ROR, Tax Rates & Special Factors
Schedule 12	16	Allocation Factors
Schedule 12.1	17	Allocation Factors
Schedule 12.2	18	Allocation Factors

Q. WHAT JURISDICTIONAL RATE CLASSES WERE USED IN THE CLASS COST OF SERVICE STUDY?

A. The cost of service is organized showing the following rate classes:

Residential: (Rate RS);

Secondary Distribution Small: (Rates DS, GS-FL, EH and SP);

Secondary Distribution Large: (Rates DT);

Primary Distribution: (Rate DT and DP);

Transmission: (Rates TT);

Lighting: (Rates NSU, NSP, OL, SC, SE, SL, TL and UOLS combined); and

Other: (Flood Control Water Pumping Stations).

Q. WHAT ARE THE ELEMENTS OF A COST OF SERVICE STUDY?

A. Much like the components of the overall revenue requirement, the elements of a cost of service study consist of the following elements, which are allocated to each function, classification and rate class:

Operating & Maintenance Expense
+ Depreciation
+ Other Taxes
+ Federal Income Tax
+ State Income Tax
+ Return (Jurisdictional Capitalization x Rate of Return (ROR))
- Revenue Credits
= Class Revenue Requirement or Cost of Service

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-1.

A. Schedule FR-16(7)(v)-1 is a functional cost of service study that separates the cost items into the production, transmission and distribution functions.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-2.

A. Schedule FR-16(7)(v)-2 is a classified cost of service study that separates the cost items contained in the production function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-3.

A. Schedule FR-16(7)(v)-3 is an allocated cost of service study that allocates the cost items contained in the production demand classification from Schedule FR-16(7)(v)-2 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-4.

A. Schedule FR-16(7)(v)-4 is an allocated cost of service study that allocates the cost items contained in the production energy classification from Schedule FR-16(7)(v)-2 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-5.

A. Schedule FR-16(7)(v)-5 is an allocated cost of service study that allocates the cost items contained in the production customer classification from Schedule FR-16(7)(v)-2 to the various rate groups. As is evident on the schedule, there are no production costs classified as customer related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-6.

A. Schedule FR-16(7)(v)-6 is a classified cost of service study that separates the cost items contained in the transmission function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-7.

A. Schedule FR-16(7)(v)-7 is an allocated cost of service study that allocates the cost items contained in the transmission demand classification from Schedule FR-16(7)(v)-6 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-8.

A. Schedule FR-16(7)(v)-8 is an allocated cost of service study that allocates the cost items contained in the transmission energy classification from Schedule FR-16(7)(v)-6 to the various rate groups. As is evident on the schedule, there are no transmission costs classified as energy related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-9.

A. Schedule FR-16(7)(v)-9 is an allocated cost of service study that allocates the cost items contained in the transmission customer classification from Schedule FR-16(7)(v)-6 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-10.

A. Schedule FR-16(7)(v)-10 is a classified cost of service study that separates the cost items contained in the distribution function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-11.

A. Schedule FR-16(7)(v)-11 is an allocated cost of service study that allocates the cost items contained in the distribution demand classification from Schedule FR-16(7)(v)-10 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-12.

A. Schedule FR-16(7)(v)-12 is an allocated cost of service study that allocates the cost items contained in the distribution energy classification from Schedule FR-16(7)(v)-10 to the various rate groups. As is evident on the schedule, there are no distribution costs classified as energy related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-13.

A. Schedule FR-16(7)(v)-13 is an allocated cost of service study that allocates the cost items contained in the distribution customer classification from Schedule FR-16(7)(v)-10 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-14.

A. Schedule FR-16(7)(v)-14 is a total class cost of service study that sums the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-4, FR-16(7)(v)-5, FR-16(7)(v)-7, FR-16(7)(v)-8, FR-16(7)(v)-9, FR-16(7)(v)-11, FR-16(7)(v)-12 and FR-16(7)(v)-13, by the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-15.

A. Schedule FR-16(7)(v)-15 is a classified cost of service study for the residential class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-16.

A. Schedule FR-16(7)(v)-16 is a classified cost of service study for the Distribution Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-17.

A. Schedule FR-16(7)(v)-17 is a classified cost of service study for the GSFL Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-18.

A. Schedule FR-16(7)(v)-18 is a classified cost of service study for the EH Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-

16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-19.

A. Schedule FR-16(7)(v)-19 is a classified cost of service study for the SP Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-20.

A. Schedule FR-16(7)(v)-20 is a classified cost of service study for the DT Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-21.

A. Schedule FR-16(7)(v)-21 is a classified cost of service study for the DT Primary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-22.

A. Schedule FR-16(7)(v)-22 is a classified cost of service study for the Distribution Primary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-23.

A. Schedule FR-16(7)(v)-23 is a classified cost of service study for the Time-of-Day Rate for Service at Transmission Voltage (Rate TT) class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-24.

A. Schedule FR-16(7)(v)-24 is a classified cost of service study for the Lighting class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-25.

A. Schedule FR-16(7)(v)-25 is a classified cost of service study for the Other – Water Pumping class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. HOW DID YOU DEVELOP THE COST OF SERVICE STUDY THAT YOU USED TO ALLOCATE COSTS TO THE DIFFERENT RATE CLASSES?

A. First, I developed various allocation factors based on customer, energy usage, and demand statistics for the test period. Next, I functionalized costs into the specific utility functions, *i.e.,* production, transmission and distribution. I then classified the costs as demand, energy or customer related, or a combination in some instances. Lastly, I allocated the demand, energy and customer related costs to rate classes based on the cost causation guidelines published in the NARUC "Electric

Utility Cost Allocation Manual," my utility company experience, and my knowledge of cost of service studies.

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW YOU FUNCTIONALIZE COSTS.

A. The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to the load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer.

The Company's accounting records use the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounts functionalize the Company's investment into the primary categories of production (generation), transmission, distribution, and general plant. Similarly, the Company's operating costs are categorized into production, transmission, distribution, customer services, and administrative and general (A&G) functions.

B. Classifying Costs

Q. PLEASE EXPLAIN THE CLASSIFICATION OF COSTS.

A. Next, functionalized costs are grouped according to their cost-causation characteristics. This process is known as classification of costs. Typically, these cost-causing characteristics are defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are fixed costs incurred regardless of the level of energy sales and have a direct relationship to the kilowatts (kW) of demand that customers place on the various segments of the system. Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. Until the Company has the full ability to bill all customers based on demand (both from a technical and a regulatory perspective), the Company will continue to use fixed charges as a proxy for demand-based billing.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt hours (kWh) generated and delivered. These costs are often referred to as variable costs. Fuel is an example of an energy-related cost.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred primarily as a result of the number of customers being served. These fixed costs include items of investment and related expenses in functional categories such as metering, and costs associated with customer accounting and sales. Customer costs do not vary significantly with the customers' volume of usage, but are influenced more by factors such as number of customers.

C. Allocation of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED TO VARIOUS CUSTOMER CLASSES.

A. The allocation of costs is the process of multiplying the functionalized and classified costs by allocation factors, resulting in costs being assigned to customer classes. Some costs are directly assignable to a single class of customers. Most costs, however, are attributable to more than one type of customer. Costs are allocated to the various customer groups in relationship to how those customers influence the Company to incur the costs. This relationship is referred to as "cost causation." Specific allocation factors are developed that relate to the demand, energy, and customer classifications identified above, to accomplish a proper matching of the costs to the customer groups, based on cost causation.

Q. PLEASE DESCRIBE THE ALLOCATION METHODOLOGY YOU USED IN THIS PROCEEDING TO ALLOCATE DEMAND-RELATED COSTS.

A. Each customer class' cost responsibility (*i.e.*, the percentage of the demand related costs assigned to each customer class) is equal to the ratio of their demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates production and transmission demand-related costs based upon the 12 monthly coincident peaks (12 CP).

Q. HOW WERE THE DEMAND VALUES DEVELOPED FROM COMPANY CUSTOMER LOAD RESEARCH DATA?

A. kWh sales and load research data for the twelve months ended December 31, 2018, were used to calculate the monthly peak contributions. The calculations of the monthly demands appear on pages 11 through 32 of work paper FR-16(7)(v). The following is an example of how the class group demand was calculated for rate RS for the month of December 2018.

Step 1 – Determine the average demand by dividing the total kWh by the number of hours in the month.

137,578,627 kWh ÷ 744 hours = 184,918 kW

Step 2 – Determine the coincident peak demand by dividing the average demand from Step 1 by the coincident peak load factor supplied by load research.

184,918 kW ÷ 69.04 percent = 267,834 kW

Step 3 – To determine the demand at generation, line losses are added by multiplying the coincident peak demand from step 2 by the loss factor.

267,834 x 1.0358 = 277,422 kW (with losses)

This process was followed for all customer classes for the twelve months of the test year to determine each class' monthly peak coincident with Duke Energy Kentucky's monthly system peak. I used a similar procedure to develop each class's diversified class peak and highest (single) non-coincident peak demands.

Q. PLEASE DESCRIBE HOW THE 12 CP DEMAND ALLOCATOR WAS USED TO ALLOCATE COSTS.

A. The 12 CP demand allocator was used to allocate Production and Transmission capacity related investments and expenses to the customer groups.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE DISTRIBUTION RELATED COSTS TO THE VARIOUS RATE CLASSES.

A. Several different allocation factors were used to allocate distribution plant to the customer classes. First, distribution plant was grouped by the type of plant such as substations, poles, conductors, *etc.* Then it was determined whether each type is customer- or demand-related factor. Finally, each customer- or demand-related cost was allocated to rate class.

Substations are considered 100 percent demand-related and were allocated using the average class group coincident peak demand ratios for the twelve months ending December 31, 2018. This factor takes into consideration the load diversity by rate group at the distribution substation level.

Poles and conductors are allocated partially on demand and partially based on customer counts using the minimum size method.

Transformers were allocated between customer and demand using the minimum size method. Transformers, as well as other distribution plant facilities, are considered to have a customer component because the number of facilities needed on the system, are dependent on the number of customers. The remaining costs are demand-related. I allocated the demand portion of transformers among the customer classes using the maximum non-coincident peak load ratios. The maximum non-coincident peak demand allocator is appropriate because transformers are sized to meet the maximum demand and are close to the customer so there is little or no load diversity. I then allocated the customer portion of transformers among the customer classes based on the total number of customers.

Services are considered 100 percent customer-related and were allocated based on a weighted-average number of customers (K217). The weighting is based on an engineering analysis that prices various service drop costs based on demands. For example, it is twice as costly for a service drop at 100 kVA versus a service drop at 25 kVA. Customers with an average demand of 100 kVA are weighted at twice the cost of customers with an average demand of 25 kVA.

Other distribution and customer service related costs can be more directly associated with a customer statistic such as the cost of meters (K407), customer charge-offs (K411) and other customer-related studies. As an example, the investment in meters can be directly associated with the costs of metering the various customer groups (K407).

Street lights were directly assigned to the street lighting rate class.

Q. PLEASE DESCRIBE THE MINIMUM SIZE METHOD USED TO ALLOCATE TRANSFORMER COSTS BETWEEN CUSTOMER- AND DEMAND-RELATED COSTS.

A. The minimum size study is shown on Work Paper FR-16(7)(v), page 53. The minimum size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the customer. For transformers, the study involved determining the minimum size transformer currently installed by Duke Energy Kentucky. In this case, it is a 25 kVa transformer. Duke Energy Kentucky's 2018 average cost of a 25 kVa transformer was $1,633.

I used asset accounting records to determine the number of overhead and pad-mounted transformers installed each year from 1910 to 2018. I then used the Handy-Whitman Index for Utility Plant Materials (specifically line transformers) to calculate the cost per transformer for each of the years 1910 to 2018, beginning with a 2018 Handy-Whitman index of 995 and 2018 cost of $1,633. For each year, I multiplied the number of transformers by the cost per transformer to get the minimum size cost per year. I summarized each of the years 1910 to 2018 to arrive at the minimum size transformer cost of approximately $15 million. This was classified as a customer-related cost. The difference between this customer-related cost and the balance in FERC Line Transformer account 368 is the demand component, resulting in allocation factors of 24.53 percent to customer and 75.47 percent to demand. I allocated all transformer-related cost (plant, accumulated depreciation) to customer and demand using these factors.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE COMMON AND GENERAL PLANT.

A. I functionalized common and general plant based on functional salaries and wages as presented on pages 354-355 of Duke Energy Kentucky's 2018 FERC Form 1 annual report. I then used distribution kW and various weighted O&M expense ratios to allocate each function to customer classes.

Q. PLEASE EXPLAIN HOW YOU ALLOCATED A & G EXPENSES USING THIS METHODOLOGY.

A. I functionalized A&G expenses based on the same functional salaries and wages used for general and common plant. After I functionalized the expenses, I allocated the expenses to rate classes based on the allocation of direct O&M for that function.

For example, A&G expenses functionalized as distribution were allocated to rate classes based on each rate class' allocation of direct distribution O&M.

Q. WHAT ARE THE RATE BASE ADJUSTMENTS THAT YOU IDENTIFY IN THE COST OF SERVICE?

A. While net plant is the largest single component of rate base, there are other items which must be added to or subtracted from rate base. These items include accumulated deferred income taxes (ADIT), miscellaneous deferrals, and working capital which includes materials and supplies and prepayments.

Q. HOW DID YOU ALLOCATE THE ADJUSTMENTS THAT WERE SUBTRACTED FROM RATE BASE?

A. I allocated the subtractive adjustments based on the net plant ratios and other allocators for each rate class.

Q. HOW DID YOU ALLOCATE ADJUSTMENTS THAT WERE ADDED TO RATE BASE?

A. I used various factors to allocate the amounts reflected in the Accumulated Deferred Income Tax Account 190.

Q. HOW DID YOU ALLOCATE WORKING CAPITAL?

A. Working capital consists of the following items: fuel inventories, emission allowances, materials and supplies, prepayments, cash, and other miscellaneous items. Fuel Inventories and emission allowances were allocated to rate groups based on K301, class kWh ratios; materials and supplies were allocated using PD29, class net plant ratios; general insurance and excise tax were allocated to rate groups using net plant ratios NP29, Collateral asset was allocated to rate groups based on K301 class kWh ratios.

Cash working capital is equal to 1/8 of non-fuel O&M expense minus the fuel costs and fuel and purchased power adjustment.

Q. HOW DID YOU ALLOCATE DEPRECIATION EXPENSES?

A. I allocated depreciation expenses to rate class based on the functional class net-depreciable plant ratios.

Q. HOW DID YOU ALLOCATE REAL ESTATE AND PROPERTY TAXES?

A. I allocated real estate and property taxes to rate class based on the functional class net plant ratios.

Q. HOW DID YOU ALLOCATE PAYROLL AND HIGHWAY TAXES, THE PSC ASSESSMENT AND OTHER MISCELLANEOUS TAXES?

A. I allocated the PSC Maintenance Taxes to class based on each rate class revenue ratio. I allocated Payroll, Highway and Other Miscellaneous Taxes to rate class based the class-weighted A&G expense ratio (A315).

Q. HOW DID YOU ALLOCATE FEDERAL AND STATE INCOME TAX ADJUSTMENTS AND DEDUCTIONS?

A. I reviewed each income tax adjustment and deduction to determine the functional cause of the adjustment and deduction, then selected the appropriate allocation factor. For example, an "Other Deductions" item, tax depreciation in excess of book depreciation, was allocated to the rate classes based on the class depreciation expense ratio (DE49).

Q. HOW DID YOU ALLOCATE OTHER OPERATING REVENUES?

A. I evaluated each other operating revenue item to determine the source of the revenue, then selected the appropriate allocation factor. The class ratio of present revenues was the primary allocation factor used to allocate the revenue credits to the respective rate groups.

Q. DID YOU USE ANY OTHER ALLOCATION FACTORS IN THE COST OF SERVICE STUDY?

A. Yes, there are many plant and expense ratios that were developed internally in the cost of service study. The cost of service study lists each item's allocation factor under the column identified as "ALLO."

IV. RESULTS OF COST OF SERVICE STUDY

Q. WHAT DO THE RESULTS OF THE COST OF SERVICE STUDY SHOW?

A. Schedule FR-16(7)(v)-14, page 1 of 15, is a summary of the cost of service study that shows the costs allocated to each rate class.

Q. HOW WERE THE RESULTS OF YOUR COST OF SERVICE STUDY USED IN THESE PROCEEDINGS?

A. The results of the fully allocated cost of service study by rate class were supplied to Duke Energy Kentucky witness Jeff Kern, who used this data to develop the proposed rate design for these proceedings.

V. DISTRIBUTION OF PROPOSED REVENUE INCREASE

Q. DID THE COST OF SERVICE STUDY SHOW THAT THE INCREASE REQUIRED FOR EACH CUSTOMER CLASS WAS PROPORTIONAL?

A. No. The cost of service study revealed that there are significant differences among the rate classes when comparing the actual return earned by each rate class to the 6.711 percent overall return on rate base being requested in this case. Put another way, developing rates that generate the amount of revenue that equals the allocated revenue requirement for each rate class will mean much greater increases for some rate classes, in terms of percentage increases, than other classes.

To mitigate the rate shock that may come from eliminating the subsidy/excess (or rate disparities) among the rate classes, the Company is proposing to use a two-step process to distribute the proposed revenue increase. The first step eliminates 5 percent of the subsidy/excess revenues between customer classes based on present revenues. The second step allocates the rate increase to customer classes based on electric original cost depreciated (OCD) rate base.

Q. THE WATER PUMPING RATE CLASS APPEARS TO BE RECEIVING A VERY LARGE RATE INCREASE. PLEASE EXPLAIN HOW THIS IS BEING HANDLED IN THE PROPOSED RATES.

A. The customers in this class are served under special contracts. The rates for these customers will not change. The proposed rate increase for this class was added to the proposed revenues for Rate DS.

Q. PLEASE EXPLAIN IN GREATER DETAIL THE FIRST STEP THAT ELIMINATES 5 PERCENT OF THE SUBSIDY/EXCESS REVENUES.

A. Again, it is a general tenet of ratemaking that each class should, to the extent practicable, pay the costs of providing service to that class. The elimination of a portion of the subsidy/excess takes into consideration that the Company is not earning the same rate of return on all customer classes. It is unlikely that equal rates of return across all rate classes are achievable; nonetheless, to the extent possible, large variances among the customer classes should be eliminated. A comparison of revenues under present rates and at the retail average rate of return is made and then 5 percent of that amount is added to, or subtracted from, the rate increase to determine the proposed revenues in this proceeding.

Admittedly, this proposal lets a subsidy/excess persist but it will reduce the gap so that each class is paying rates that more closely reflect their costs of service.

Q. HOW DID THIS RATE DISPARITY ARISE?

A. Rate disparities exist mostly because over the years rates have not been set based on the cost to serve customers as determined by a cost of service study. Other factors include: (1) customer mix often changes between rate cases, *i.e.,* residential, for example, may make up more or less of the total today than it did the last time rates were set; (2) different asset classes depreciate at different rates and because different asset classes are allocated differently, long periods between rate cases can shift the relative costs to serve each rate class. Also, regulators may purposely allow subsidy/excesses to persist in the interest of rate gradualism.

Q. WHY DID YOU PROPOSE A FIVE PERCENT REDUCTION OF THE SUBSIDY/EXCESS REVENUES IN THESE PROCEEDINGS?

A. The present rate of returns by class shown on Work Paper FR-16(7)(v), page 1, indicate that there is a significant difference in those returns. To ensure that each rate class pays the actual cost to serve that class, and move each class to the average rate of return, 100 percent of the subsidy/excess would need to be eliminated. However, given the wide disparity among rate classes, complete elimination of the subsidy excess would cause a dramatic swing in rate impacts between and among various rate classes. By proposing to eliminate only five percent of the subsidy/excess, the Company is choosing to invoke the rate making principle of gradualism so to mitigate the volatility of 100 percent subsidy/excess elimination.

VI. CONCLUSION

Q. WERE ATTACHMENTS JEZ-1 THROUGH JEZ-4, SCHEDULES B-7, B-7.1, B-7.2, D-3, D-4 AND D-5, AS WELL AS, FR 16(7)(v), AND WORKPAPER FR 16(7)(v), PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, James E. Ziolkowski, Director, Rates & Regulatory Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

James E. Ziolkowski Affiant

Subscribed and sworn to before me by James E. Ziolkowski on this 30th day of August, 2019.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

DUKE ENERGY KENTUCKY, INC.
ELECTRIC COST OF SERVICE STUDY
CASE NO: 2019-00271
ALLOCATION FACTORS FOR COST OF SERVICE STUDY

Attachment JEZ-1
Witness Responsibl
James E. Ziolkowsk
Page 1 of 1

LINE NO.	RATE GROUP	12 CP DEMAND RATIO %	AVG & EXCESS RATIO %	DIFFERENCE %	PROD STACKING RATIO %	DIFFERENCE %
1		A	B	C = B - A	D	E = D - A
2	**Retail:**					
3	Residential	45.078%	51.035%	5.957%	40.216%	-4.862%
4	Dist Secondary - DS	27.064%	23.429%	-3.635%	26.955%	-0.109%
5	Dist Secondary - GS-FL	0.130%	0.105%	-0.025%	0.144%	0.014%
6	Dist Secondary - EH	0.513%	0.596%	0.083%	0.455%	-0.058%
7	Dist Secondary - SP	0.007%	0.007%	0.000%	0.007%	0.000%
8	Dist Secondary - DT	13.494%	11.968%	-1.527%	15.515%	2.021%
9	Dist Primary - DT	8.921%	7.847%	-1.074%	10.641%	1.720%
10	Dist Primary - DP	0.431%	0.438%	0.007%	0.503%	0.072%
11	Transmission	4.227%	4.091%	-0.137%	5.206%	0.979%
12	Lighting	0.124%	0.456%	0.332%	0.336%	0.212%
13	Other	0.011%	0.029%	0.018%	0.022%	0.011%
14	Total Retail	100.000%	100.000%	0.000%	100.000%	0.000%

K201 Generation Allocator Using 12 CP

Line No.	Rate Class	Jurisdictional Electric Rate Base (A)	Present Revenues (B)	Net Operating Income (C)	Present ROR (D)	Present Revenues At Average ROR (E)	Inter Class Subsidization Overcollected (Undercollected) (F)	Inter Class Subsidization times 5.00% (G)	Rate Increase (Allocated to class based on Rate Base) (H)	Proposed Revenues 95.00% Interclass Subsidization (I)	Proposed Percent Increase (J)	ROR At Proposed Rates (K)	Proposed Increase Less (Subsidy) Excess (L)
		FR-16(7)(v)-14, page1	FR-16(7)(v)-14, page1	Work Paper FR-16(7)(v), Page 2	(C) / (A)	(C))/(1-CompositeTaxRate))	(B) - (E)	(F) * 5.00%	(H) Line 5 * ((A) / (A) Line 5)	(B) - (G) + (H)	((H) - (G)) / (B)	((((H) - (G))*(1-CompositeTaxRate)+ (C)) / (A)	(H) - (G)
1	Rate RS	$ 468,128,678	$ 123,883,637	$ 1,538,370	0.3286%	$ 141,108,988	$ (17,225,351)	$ (861,268)	$ 22,572,034	$ 147,196,005	18.818%	4.086674%	$ 23,433,302
2	Rate DS	242,499,761	90,318,223	16,285,957	6.7159%	78,609,822	11,708,401	585,420	11,692,734	101,425,537	12.298%	10.154550%	11,107,314
3	Rate GS-FL	1,195,789	577,046	157,588	13.1786%	416,373	160,673	8,034	57,636	626,648	8.596%	16.292748%	49,602
4	Rate EH	4,690,299	600,937	(430,713)	-9.1831%	1,367,764	(766,827)	(38,341)	226,164	865,442	44.016%	-4.949277%	264,505
5	Rate SP	71,824	29,960	7,474	10.4060%	22,962	6,998	350	3,468	33,078	10.408%	13.665347%	3,118
6	Rate DT - Secondary	117,799,323	46,910,116	6,718,600	5.7034%	42,811,121	4,098,995	204,950	5,679,984	52,385,150	11.671%	9.192731%	5,475,034
7	Rate DT-Primary	77,794,031	29,943,872	3,000,244	3.8567%	29,150,584	793,288	39,664	3,751,061	33,655,269	12.395%	7.438323%	3,711,397
8	Rate DP	3,811,936	1,361,377	90,448	2.3728%	1,397,850	(36,473)	(1,824)	183,816	1,547,017	13.636%	6.028871%	185,640
9	Rate TT	25,639,048	14,062,168	1,780,987	6.9464%	12,745,535	1,316,633	65,832	1,236,237	15,232,573	8.323%	10.373503%	1,170,405
10	Lighting	4,693,957	1,876,470	116,115	2.4737%	1,915,071	(38,601)	(1,930)	226,347	2,104,747	12.165%	6.124760%	228,277
11	Other - Water Pumping	103,180	16,848	(10,126)	-9.8139%	34,584	(17,736)	(887)	4,974	22,709	34.788%	-5.549277%	5,861
12													
13	Total	$ 946,427,826	$ 309,580,654	$ 29,254,944	3.0911%	$ 309,580,654	$ -	$ -	$ 45,634,456	$ 355,094,176	14.702%	6.711020%	$ 45,634,456

K201 Generation Allocator Using Average and Excess Method

Line No.	Rate Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Rate RS	$ 499,122,193	$ 123,883,637	$ 262,391	0.0526%	$ 144,084,707	$ (20,201,070)	$ (1,010,053)	$ 24,066,462	$ 148,839,218	20.144%	3.824425%	$ 25,076,515
2	Rate DS	223,587,870	90,318,223	17,064,637	7.6322%	76,793,950	13,524,273	676,214	10,780,865	100,422,874	11.188%	11.025058%	10,104,651
3	Rate GS-FL	1,070,320	577,046	162,951	15.2245%	404,063	172,983	8,649	51,608	620,005	7.445%	18.237779%	42,959
4	Rate EH	5,118,985	600,937	(448,520)	-8.7619%	1,409,133	(808,196)	(40,410)	246,825	888,172	47.798%	-4.549312%	287,235
5	Rate SP	71,824	29,960	7,473	10.4046%	22,963	6,997	350	3,463	33,073	10.391%	13.658689%	3,113
6	Rate DT - Secondary	109,858,177	46,910,116	7,045,493	6.4133%	42,048,734	4,861,382	243,069	5,297,095	51,964,142	10.774%	9.867083%	5,054,026
7	Rate DT-Primary	72,205,430	29,943,872	3,230,328	4.4738%	28,614,010	1,329,862	66,493	3,481,571	33,358,950	11.405%	8.024596%	3,415,078
8	Rate DP	3,848,532	1,361,377	88,975	2.3119%	1,401,319	(39,942)	(1,997)	185,567	1,548,941	13.778%	5.970806%	187,564
9	Rate TT	24,928,057	14,062,168	1,810,192	7.2617%	12,677,360	1,384,808	69,240	1,201,970	15,194,898	8.055%	10.673067%	1,132,730
10	Lighting	6,424,384	1,876,470	45,011	0.7006%	2,081,029	(204,559)	(10,228)	309,768	2,196,466	17.053%	4.440080%	319,996
11	Other - Water Pumping	192,054	16,848	(13,987)	-7.2828%	43,386	(26,538)	(1,327)	9,260	27,435	62.841%	-3.144188%	10,587
12													
13	Total	$ 946,427,826	$ 309,580,654	$ 29,254,944	3.0911%	$ 309,580,654	$ -	$ -	$ 45,634,456	$ 355,094,176	14.702%	6.711020%	$ 45,634,456

K201 Generation Allocator Using Production Stacking Method

Line No.	Rate Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Rate RS	$ 442,841,437	$ 123,883,637	$ 2,579,985	0.5826%	$ 138,680,391	$ (14,796,754)	$ (739,838)	$ 21,352,741	$ 145,855,282	17.736%	4.327952%	$ 22,092,579
2	Rate DS	241,929,922	90,318,223	16,309,315	6.7413%	78,555,246	11,762,977	588,149	11,665,274	101,395,348	12.265%	10.178755%	11,077,125
3	Rate GS-FL	1,268,979	577,046	154,581	12.1815%	423,392	153,654	7,683	61,187	630,550	9.272%	15.346916%	53,504
4	Rate EH	4,387,082	600,937	(418,293)	-9.5347%	1,338,736	(737,799)	(36,890)	211,534	849,361	41.340%	-5.283435%	248,424
5	Rate SP	71,824	29,960	7,473	10.4046%	22,963	6,997	350	3,463	33,073	10.391%	13.658689%	3,113
6	Rate DT - Secondary	128,312,584	46,910,116	6,285,530	4.8986%	43,820,839	3,089,277	154,464	6,186,922	52,942,574	12.860%	8.428161%	6,032,458
7	Rate DT-Primary	86,744,157	29,943,872	2,631,796	3.0340%	30,009,866	(65,994)	(3,300)	4,182,593	34,129,765	13.979%	6.656760%	4,185,893
8	Rate DP	4,183,116	1,361,377	75,006	1.7931%	1,433,702	(72,325)	(3,616)	201,700	1,566,693	15.082%	5.477891%	205,316
9	Rate TT	30,731,000	14,062,168	1,571,378	5.1133%	13,234,388	827,780	41,389	1,481,774	15,502,553	10.243%	8.632149%	1,440,385
10	Lighting	5,797,039	1,876,470	70,683	1.2193%	2,021,004	(144,534)	(7,227)	279,519	2,163,216	15.281%	4.932818%	286,746
11	Other - Water Pumping	160,686	16,848	(12,510)	-7.7854%	40,127	(23,279)	(1,164)	7,748	25,760	52.896%	-3.621602%	8,912
12													
13	Total	$ 946,427,826	$ 309,580,654	$ 29,254,944	3.0911%	$ 309,580,654	$ -	$ -	$ 45,634,456	$ 355,094,176	14.702%	6.711020%	$ 45,634,456

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
CALCULATION OF AVERAGE & EXCESS ALLOCATOR
CASE NO. 2019-00271

Attachment JEZ-3
Witness Responsible:
James E. Ziolkowski
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Line No.	Rate Group	Annual Usage (a) (kWh)	System Hour CP (b) (kW)	Class Maximum NCP Demand (c) (kW)	Average Hourly Demand (kW) (Col. 1 / 8,760 hrs)	Excess Demand (Hourly kW) (Col.3 - Col.4)	Excess Demand Ratio (%)	Allocated Excess Demand (kW)	Average & Excess Hourly Demand (kW) (Col.4 + Col. 7)	Average & Excess Hourly Demand (Ratio) K201
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1										
2										
3	Residential	1,573,474,084		899,439	179,620	719,819	69.2120%	238,358	417,978	51.0351%
4	Dist Secondary - DS	1,117,233,456		321,857	127,538	194,319	18.6842%	64,346	191,884	23.4291%
5	Dist Secondary - GS-FL	6,253,450		1,158	714	444	0.0427%	147	861	0.1051%
6	Dist Secondary - EH	17,753,941		10,653	2,027	8,626	0.8294%	2,856	4,883	0.5962%
7	Dist Secondary - SP	290,270		109	33	76	0.0073%	25	58	0.0071%
9	Dist Secondary - DT	684,960,142		138,051	78,192	59,859	5.7556%	19,822	98,014	11.9675%
10	Dist Primary - DT	475,731,674		84,382	54,307	30,075	2.8918%	9,959	64,266	7.8469%
8	Dist Primary - DP	22,308,907		5,687	2,547	3,140	0.3019%	1,040	3,587	0.4380%
11	Transmission	240,327,025		45,755	27,435	18,320	1.7615%	6,066	33,501	4.0905%
12	Lighting	18,114,621		7,098	2,068	5,030	0.4836%	1,665	3,733	0.4558%
13	Other	1,156,042		444	132	312	0.0300%	103	235	0.0287%
14	Total	4,157,603,612	819,000	1,514,633	474,613	1,040,020	100.0000%	344,387	819,000	100.0000%

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
CALCULATION OF PRODUCTION STACKING (TOD) ALLOCATOR
CASE NO. 2019-00271

Attachment JEZ-4
Witness Responsible:
James E. Ziolkowski
Page 1 of 1

		Baseload		Peak			
Line No.	Rate Group	Annual Usage (a) (kWh)	East Bend Net Plant (Allocated on kWh)	12CP Demand (kW)	Woodsdale Net Plant (Allocated on 12CP)	Total Revenue Requirement	Allocator K201
		(1)	(2)	(3)	(4)	(5)	(6)
1							
2							
3	Residential	1,573,474,084	$131,774,101	323,558	$74,584,940	$206,359,041	40.2163%
4	Dist Secondary - DS	1,117,233,456	$93,565,211	194,112	$44,745,708	$138,310,919	26.9547%
5	Dist Secondary - GS-FL	6,253,450	$523,709	933	$215,070	$738,780	0.1440%
6	Dist Secondary - EH	17,753,941	$1,486,843	3,682	$848,756	$2,335,599	0.4552%
7	Dist Secondary - SP	290,270	$24,309	51	$11,756	$36,066	0.0070%
9	Dist Secondary - DT	684,960,142	$57,363,517	96,516	$22,248,376	$79,611,893	15.5152%
10	Dist Primary - DT	475,731,674	$39,841,212	64,029	$14,759,639	$54,600,850	10.6409%
8	Dist Primary - DP	22,308,907	$1,868,309	3,090	$712,291	$2,580,600	0.5029%
11	Transmission	240,327,025	$20,126,723	28,569	$6,585,580	$26,712,304	5.2058%
12	Lighting	18,114,621	$1,517,049	891	$205,389	$1,722,438	0.3357%
13	Other	1,156,042	$96,815	79	$18,211	$115,026	0.0224%
14	Total	4,157,603,612	$348,187,800	715,510	$164,935,716	$513,123,516	100.0000%