REDACTED

INFORMATION SHEET

PRESIDING: Commissioner Clodfelter, Presiding; Chair Mitchell; and Commissioners Brown-Bland, Gray, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Wednesday, September 30, 2020
TIME: 1:31 p.m. – 4:31 p.m.
DOCKET NOS.: E-2, Sub 1219 and E-2, Sub 1193
COMPANY: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC
DESCRIPTION: E-2, Sub 1219, In the Matter of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-2, Sub 1193, Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 14

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Somers, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Schauer, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, Luhr and Coxton

REPORTED BY: Joann Bunze
TRANSCRIPT PAGES: 159
PREFILED PAGES: 596
TOTAL PAGES: 755
DATE FILED: October 7, 2020

Calculation of Proposed Additional Operating Income

(1)	**($000)**	Smith Exhibit 1 Page 1	Operating Income Before Increase	$	356,031
(2)	**($000)**	Smith Exhibit 1 Page 1	Adjusted Operating Income After Increase	$	804,903
(3)	**($000)**	**(2) - (1)**	Additional Operating Income	$	448,872
(4)	**(%)**	**(3) / (1)**	Additional Operating Income		126.1%

Calculation of Revenue Requirement Impact of DEP's Proposed ROE vs. Current ROE

(1)	Smith Exhibit 1 Page 1	DEP requested rate of return			7.41%
		1) Calculate Rate of Return Using ROE = 9.9% and Equity Ratio = 52%			
		Capital Component	**Percentage of Total**	**Cost**	**Weighted Cost**
(2)	Smith Exhibit 1 Page 2	Long Term Debt	48.00%	4.15%	1.99%
(3)		Member's Equity	52.00%	9.90%	5.15%
(4)	(2)+(3)	**Rate of Return (ROE = 9.9% and Equity Ratio = 52%)**			**7.14%**
		2) Calculate Revenue Requirement Impact at the Proposed ROE			
(5)	Smith Exhibit 1 Page 2	Rate Base ($000)			$ 10,859,981
(6)	= (4)	Rate of Return (ROE = 9.9% and Equity Ratio = 52%)			7.14%
(7)	(5) x (6)	Adjusted Income Requirement (ROE = 9.9% and Equity Ratio = 52%)			$ 775,403
(8)	Commercial Group Exh. CR-1	DEP Proposed Income Requirement ($000)			$ 804,903
(9)	(8) - (7)	Difference in Income Requirement ($000)			$ 29,500
(10)	Smith Exhibit 1 Page 2	Conversion Factor			1.3054
(11)	(9) x (10)	**Difference in Revenue Requirement ($000)**			**$ 38,510**
(12)	Smith Exhibit 1 Page 1	Requested Revenue Requirement Increase ($000)			$ 585,961
(13)	(11) / (12)	**Percent of Increase from ROE Increase**			**6.57%**

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
Washington	Avista Corp.	UE-150204	9.90%	1/6/2016	V	9.50%	(40)
Arkansas	Entergy Arkansas Inc.	15-015-U	10.20%	2/23/2016	V	9.75%	(45)
Indiana	Indianapolis Power & Light Co.	44576	10.93%	3/16/2016	V	9.85%	(108)
Massachusetts	Fitchburg Gas & Electric Light	15-80	10.25%	4/29/2016	D	9.80%	(45)
Maryland	Baltimore Gas and Electric Co.	9406	10.60%	6/3/2016	D	9.75%	(85)
New Mexico	El Paso Electric Co.	15-00127-UT	9.95%	6/8/2016	V	9.48%	(47)
New York	NY State Electric & Gas Corp.	15-E-0283	10.06%	6/15/2016	D	9.00%	(106)
New York	Rochester Gas & Electric Corp.	15-E-0285	10.06%	6/15/2016	D	9.00%	(106)
Indiana	Northern Indiana Public Service Co.	44688	10.75%	7/18/2016	V	9.98%	(77)
Tennessee	Kingsport Power Company	16-00001	10.66%	8/9/2016	V	9.85%	(81)
Arizona	UNS Electric Inc.	E-04204A-15-0142	9.50%	8/18/2016	V	9.50%	-
New Jersey	Atlantic City Electric Co.	ER-16030252	10.60%	8/24/2016	D	9.75%	(85)
Washington	PacifiCorp	UE-152253	9.50%	9/1/2016	V	9.50%	-
Michigan	Upper Peninsula Power Co.	U-17895	10.75%	9/8/2016	V	10.00%	(75)
New Mexico	Public Service Co. of NM	15-00127-UT	10.50%	9/28/2016	V	9.58%	(92)
Massachusetts	Massachusetts Electric Co.	15-155	10.50%	9/30/2016	D	9.90%	(60)
Wisconsin	Madison Gas and Electric Co.	3270-UR-121	10.20%	11/9/2016	V	9.80%	(40)
Oklahoma	Public Service Company of OK	PUD 201500208	10.50%	11/10/2016	V	9.50%	(100)
Maryland	Potomac Electric Power Co.	9418	10.60%	11/15/2016	D	9.55%	(105)
Wisconsin	Wisconsin Power and Light Co	6680-UR-120	10.00%	11/18/2016	V	10.00%	-
Florida	Florida Power & Light Co.	160021-EI	11.50%	11/29/2016	V	10.55%	(95)
California	Liberty Utilities CalPeco	A15-05-008	10.50%	12/1/2016	V	10.00%	(50)
Illinois	Ameren Illinois	16-0262	8.64%	12/6/2016	D	8.64%	-
Illinois	Commonwealth Edison Co.	16-0259	8.64%	12/6/2016	D	8.64%	-
South Carolina	Duke Energy Progress Inc.	2016-227-E	10.75%	12/7/2016	V	10.10%	(65)
New Jersey	Jersey Central Power & Light Co.	ER-16040383	11.20%	12/12/2016	D	9.60%	(160)
Connecticut	United Illuminating Co.	16-06-04	9.92%	12/14/2016	D	9.10%	(82)
Colorado	Black Hills Colorado Electric	16AL-0326E	9.83%	12/19/2016	V	9.37%	(46)
Maine	Emera Maine	2015-00360	10.25%	12/19/2016	D	9.00%	(125)
North Carolina	Virginia Electric & Power Co.	E-22 Sub 532	10.50%	12/22/2016	V	9.90%	(60)
Nevada	Sierra Pacific Power Co.	16-06006	10.26%	12/22/2016	V	9.60%	(66)
Idaho	Avista Corp.	AVU-E-16-03	9.90%	12/28/2016	V	9.50%	(40)
Wyoming	MDU Resources Group Inc.	2004-117-ER-16	10.10%	1/18/2017	V	9.45%	(65)
New York	Consolidated Edison Co. of NY	16-E-0060	9.75%	1/24/2017	D	9.00%	(75)
Michigan	DTE Electric Co.	U-18014	10.50%	1/31/2017	V	10.10%	(40)
Maryland	Delmarva Power & Light Co.	9424	10.60%	2/15/2017	D	9.60%	(100)
New Jersey	Rockland Electric Company	ER-16050428	10.20%	2/22/2017	D	9.60%	(60)
Arizona	Tucson Electric Power Co.	E-01933A-15-0322	10.35%	2/24/2017	V	9.75%	(60)
Michigan	Consumers Energy Co.	U-17990	10.70%	2/28/2017	V	10.10%	(60)
Minnesota	Otter Tail Power Co.	E-017/GR-15-1033	10.05%	3/2/2017	V	9.41%	(64)
Oklahoma	Oklahoma Gas & Electric Co.	PUD 201500273	10.25%	3/20/2017	V	9.50%	(75)
Florida	Gulf Power Co.	160186-EI	11.00%	4/4/2017	V	10.25%	(75)
New Hampshire	Liberty Utilities Granite St	DE-16-383	10.30%	4/12/2017	D	9.40%	(90)
New Hampshire	Unitil Energy Systems Inc.	DE-16-384	10.30%	4/20/2017	D	9.50%	(80)
Missouri	Kansas City Power & Light	ER-2016-0285	9.90%	5/3/2017	V	9.50%	(40)
Minnesota	Northern States Power Co.	E-022/GR-15-826	10.00%	5/11/2017	V	9.20%	(80)
Arkansas	Oklahoma Gas & Electric Co.	16-052-U	10.25%	5/18/2017	V	9.50%	(75)
Delaware	Delmarva Power & Light Co.	16-0649	10.60%	5/23/2017	D	9.70%	(90)
North Dakota	MDU Resources Group Inc.	PU-16-666	10.00%	6/16/2017	V	9.65%	(35)
Kentucky	Kentucky Utilities Co.	2016-00370	10.23%	6/22/2017	V	9.70%	(53)
Kentucky	Louisville Gas & Electric Co.	2016-00371	10.23%	6/22/2017	V	9.70%	(53)
District of Columbia	Potomac Electric Power Co.	FC-1139	10.60%	7/24/2017	D	9.50%	(110)
Arizona	Arizona Public Service Co.	E-01345A-16-0036	10.50%	8/15/2017	V	10.00%	(50)
New Jersey	Atlantic City Electric Co.	ER-17030308	10.10%	9/22/2017	D	9.60%	(50)
Texas	Oncor Electric Delivery Co.	46957	10.25%	9/28/2017	D	9.80%	(45)
Maryland	Potomac Electric Power Co.	9443	10.10%	10/20/2017	D	9.50%	(60)
California	Pacific Gas & Electric Co.	Advice No. 5148-E	10.25%	10/26/2017	V	10.25%	-
California	San Diego Gas & Electric Co.	Advice No. 3120-E	10.20%	10/26/2017	V	10.20%	-
California	Southern California Edison Co.	Advice No. 3665-E	10.30%	10/26/2017	V	10.30%	-
Florida	Tampa Electric Co.	20170210-EI	N/A Ω	11/6/2017	V	10.25%	N/A

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
Alaska	Alaska Electric Light Power	U-16-086	13.80%	11/15/2017	V	11.95%	(185)
Massachusetts	NSTAR Electric Co.	17-05	10.50%	11/30/2017	D	10.00%	(50)
Massachusetts	Western Massachusetts Electric	17-05	10.50%	11/30/2017	D	10.00%	(50)
Washington	Puget Sound Energy Inc.	UE-170033	9.80%	12/5/2017	V	9.50%	(30)
Illinois	Ameren Illinois	17-0197	8.40%	12/6/2017	D	8.40%	-
Illinois	Commonwealth Edison Co.	17-0196	8.40%	12/6/2017	D	8.40%	-
Wisconsin	Northern States Power Co. - WI	4220-UR-123	10.00%	12/7/2017	V	9.80%	(20)
Texas	El Paso Electric Co.	46831	10.50%	12/14/2017	V	9.65%	(85)
Texas	Southwestern Electric Power Co.	46449	10.00%	12/14/2017	V	9.60%	(40)
Oregon	Portland General Electric Co.	UE 319	9.75%	12/18/2017	V	9.50%	(25)
New Mexico	Public Service Co. of NM	16-00276-UT	10.13%	12/20/2017	V	9.58%	(55)
Idaho	Avista Corp.	AVU-E-17-01	9.90%	12/28/2017	V	9.50%	(40)
Nevada	Nevada Power Co.	17-06003	10.10%	12/29/2017	V	9.50%	(60)
Vermont	Green Mountain Power Corp	17-3112-INV	9.50%	12/21/2017	V	9.10%	(40)
Kentucky	Kentucky Power Co.	2017-00179	10.31%	1/18/2018	V	9.70%	(61)
Oklahoma	Public Service Co. of OK	PUD 201700151	10.00%	1/31/2018	V	9.30%	(70)
Iowa	Interstate Power & Light Co.	RPU-2017-0001	10.57%	2/2/2018	V	9.98%	(59)
North Carolina	Duke Energy Progress Inc.	E-2, Sub 1142	10.75%	2/23/2018	V	9.90%	(85)
Minnesota	ALLETE (Minnesota Power)	E-015/GR-16-664	10.15%	3/12/2018	V	9.25%	(90)
New York	Niagara Mohawk Power Corp.	17-E-0238	9.79%	3/15/2018	D	9.00%	(79)
Michigan	Consumers Energy Co.	U-18322	10.50%	3/29/2018	V	10.00%	(50)
Connecticut	Connecticut Light and Power	17-10-46	10.50%	4/18/2018	D	9.25%	(125)
Michigan	DTE Electric Co.	U-18255	10.50%	4/18/2018	V	10.00%	(50)
Washington	Avista Corp.	UE-170485	9.90%	4/26/2018	V	9.50%	(40)
Indiana	Indiana Michigan Power Co.	44967	10.60%	5/30/2018	V	9.95%	(65)
Maryland	Potomac Electric Power Co.	9472	10.10%	5/31/2018	D	9.50%	(60)
New York	Central Hudson Gas & Electric	17-E-0459	9.50%	6/14/2018	D	8.80%	(70)
North Carolina	Duke Energy Carolinas LLC	E-7, Sub 1146	10.75% ‡	6/22/2018	V	9.90%	(85)
Maine	Emera Maine	2017-00198	9.50%	6/28/2018	D	9.35%	(15)
Hawaii	Hawaii Electric Light Co	2015-0170	10.60%	6/29/2018	V	9.50%	(110)
District of Columbia	Potomac Electric Power Co.	FC-1150	10.10%	8/8/2018	D	9.53%	(57)
Delaware	Delmarva Power & Light Co.	17-0977	10.10%	8/21/2018	D	9.70%	(40)
Rhode Island	Narragansett Electric Co.	4770 (electric)	10.10%	8/24/2018	D	9.28%	(82)
New Mexico	Southwestern Public Service Co	17-00255-UT	10.25%	9/5/2018	V	9.10%	(115)
Wisconsin	Wisconsin Power and Light Co	6680-UR-121 (Elec)	10.00%	9/14/2018	V	10.00%	-
Wisconsin	Madison Gas and Electric Co.	3270-UR-122 (Elec)	9.80%	9/20/2018	V	9.80%	-
North Dakota	Otter Tail Power Co.	PU-17-398	10.30%	9/26/2018	V	9.77%	(53)
Ohio	Dayton Power and Light Co.	15-1830-EL-AIR	10.50%	9/26/2018	D	9.999% *	(50)
Kansas	Westar Energy Inc.	18-WSEE-328-RTS	9.85%	9/27/2018	V	9.30%	(55)
Pennsylvania	UGI Utilities Inc.	R-2017-2640058	11.25%	10/4/2018	D	9.85%	(140)
New Jersey	Public Service Electric Gas	ER18010029	10.30%	10/29/2018	D	9.60%	(70)
Indiana	Indianapolis Power & Light Co.	45029	10.32%	10/31/2018	V	9.99%	(33)
Illinois	Ameren Illinois	18-0807	8.69%	11/1/2018	D	8.69%	-
Illinois	Commonwealth Edison Co.	18-0808	8.69%	12/4/2018	D	8.69%	-
Kansas	Kansas City Power & Light	18-KCPE-480-RTS	9.85%	12/13/2018	V	9.30%	(55)
Oregon	Portland General Electric Co.	UE-335	9.50%	12/14/2018	V	9.50%	-
Ohio	Duke Energy Ohio Inc.	17-0032-EL-AIR	10.40%	12/19/2018	D	9.84%	(56)
Texas	Texas-New Mexico Power Co.	48401	10.50%	12/20/2018	D	9.65%	(85)
Wisconsin	Madison Gas and Electric Co.	3270-UR-122 (Elec)	9.80%	12/20/2018	V	9.80%	-
Vermont	Green Mountain Power Corp.	18-0974-TF	9.30%	12/21/2018	D	9.30%	-
Michigan	Consumers Energy Co.	U-20134	10.75%	1/9/2019	V	10.00%	(75)
West Virginia	Appalachian Power Co.	18-0646-E-42T	10.22%	2/27/2019	V	9.75%	(47)
New Jersey	Atlantic City Electric Co.	ER18080925	10.10%	3/13/2019	D	9.60%	(50)
New York	Orange & Rockland Utilities Inc.	18-E-0067	9.75%	3/14/2019	D	9.00%	(75)
Oklahoma	Public Service Company of OK	PUD201800097	10.30%	3/14/2019	V	9.40%	(90)
Maryland	Potomac Edison Co.	9490	10.80%	3/22/2019	D	9.65%	(115)
Kentucky	Kentucky Utilities Co.	2018-00294	10.42%	4/30/2019	V	9.73%	(69)
Kentucky	Louisville Gas & Electric Co.	2018-00295	10.42%	4/30/2019	V	9.73%	(69)
South Carolina	Duke Energy Carolinas LLC	2018-319-E	10.50%	5/1/2019	V	9.50%	(100)
Michigan	DTE Electric Co.	U-20162	10.50%	5/2/2019	V	10.00%	(50)

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity	Reduction from Proposed
						(%)	(BP)
South Carolina	Duke Energy Progress LLC	2018-318-E	10.50%	5/8/2019	V	9.50%	(100)
South Dakota	Otter Tail Power Co.	EL18-021	10.30%	5/14/2019	V	8.75%	(155)
Hawaii	Maui Electric Company Ltd	2017-0150	10.60%	5/16/2019	V	9.50%	(110)
Michigan	Upper Peninsula Power Co.	U-20276	10.50%	5/23/2019	V	9.90%	(60)
Maryland	Potomac Electric Power Co.	9602	10.30%	8/12/2019	D	9.60%	(70)
Vermont	Green Mountain Power Corp.	19-1932-TF	9.16%	8/29/2019	V	9.06%	(10)
Wisconsin	Northern States Power Co - WI	4220-UR-124	N/A Ω	9/4/2019	V	10.00%	N/A
Massachusetts	Massachusetts Electric Co.	DPU-18-150	10.50%	9/30/2019	D	9.60%	(90)
Montana	Northwestern Corp.	D2018.2.12	10.65%	10/29/2019	V	9.65%	(100)
Wisconsin	Wisconsin Electric Power Co.	05-UR-109	10.35%	10/31/2019	V	10.00%	(35)
Wisconsin	Wisconsin Public Service Corp.	6690-UR-126	10.35%	10/31/2019	V	10.00%	(35)
Louisiana	Entergy New Orleans LLC	UD-18-07	10.50%	11/7/2019	V	9.35%	(115)
Idaho	Avista Corp.	AVU-E-19-04	9.90%	11/29/2019	V	9.50%	(40)
Illinois	Commonwealth Edison Co.	19-0387	8.91%	12/4/2019	D	8.91%	-
Indiana	Northern Indiana Public Service Co.	45159	10.80%	12/4/2019	V	9.75%	(105)
Illinois	Ameren Illinois	19-0436	8.91%	12/16/2019	D	8.91%	-
Georgia	Georgia Power Co.	42516	10.90%	12/17/2019	V	10.50%	(40)
Maryland	Baltimore Gas and Electric Co.	9610	10.30%	12/17/2019	D	9.70%	(60)
California	Pacific Gas & Electric Co.	A-19-04-015	12.00%	12/19/2019	V	10.25%	(175)
California	San Diego Gas & Electric Co.	A-19-04-017	12.38%	12/19/2019	V	10.20%	(218)
California	Southern California Edison Co.	A-19-04-014	11.45%	12/19/2019	V	10.30%	(115)
Arkansas	Southwestern Electric Power Co.	19-008-U	10.50%	12/20/2019	V	9.45%	(105)
Nevada	Sierra Pacific Power Co.	19-06002	10.21%	12/24/2019	V	9.50%	(71)
Iowa	Interstate Power & Light Co.	RPU-2019-0001	10.25%	1/8/2020	V	9.50% ¥	(75)
New York	Consolidated Edison Co. of NY	19-E-0065	9.75%	1/16/2020	D	8.80%	(95)
New Jersey	Rockland Electric Company	ER19050552	9.60%	1/22/2020	D	9.50%	(10)
Michigan	Indiana Michigan Power Co.	U-20359	10.50%	1/23/2020	V	9.86%	(64)
California	PacifiCorp	A-18-04-002	10.60%	2/6/2020	V	10.00%	(60)
Colorado	Public Service Company of Colorado	19AL-0268E	10.20%	2/11/2020	V	9.30%	(90)
Texas	Centerpoint Energy	49421	10.40%	2/14/2020	D	9.40%	(100)
Maine	Central Maine Power Co.	2018-00194	10.00%	2/19/2020	D	8.25%	(175)
North Carolina	Virginia Electric & Power Co.	E-22 Sub 562	10.75%	2/24/2020	V	9.75%	(100)
Texas	AEP Texas Inc.	49494	10.50%	2/27/2020	D	9.40%	(110)
Indiana	Indiana Michigan Power Co.	45235	10.50%	3/11/2020	V	9.70%	(80)

Entire Period				
# of Decisions	**154**			
Average (All Utilities)		**10.24%**	**9.60%**	**(64)**
Average (Distribution Only)		**10.02%**	**9.35%**	**(67)**
Average (Vertically Integrated Only)		**10.37%**	**9.74%**	**(63)**
Median		**10.28%**	**9.60%**	
Minimum		**8.40%**	**8.25%**	
Maximum		**13.80%**	**11.95%**	
North Carolina	**4**	**10.69%**	**9.86%**	**(82)**

2016				
# of Decisions	**32**			
Average (All Utilities)		**10.25%**	**9.60%**	**(65)**
Average (Distribution Only)		**10.11%**	**9.31%**	**(80)**
Average (Distribution Only, exc. IL FRP)		**10.40%**	**9.45%**	**(96)**
Average (Vertically Integrated Only)		**10.33%**	**9.77%**	**(56)**

2017				
# of Decisions	**42**			
Average (All Utilities)		**10.22%**	**9.68%**	**(54)**
Average (Distribution Only)		**10.04%**	**9.43%**	**(61)**
Average (Distribution Only, exc. IL FRP)		**10.34%**	**9.61%**	**(73)**
Average (Vertically Integrated Only)		**10.31%**	**9.80%**	**(50)**

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
2018							
# of Decisions		**36**					
Average (All Utilities)			**10.10%**			**9.54%**	**(56)**
Average (Distribution Only)			**9.96%**			**9.38%**	**(58)**
Average (Distribution Only, exc. IL FRP)			**10.14%**			**9.47%**	**(66)**
Average (Vertically Integrated Only)			**10.22%**			**9.68%**	**(54)**
2019							
# of Decisions		**33**					
Average (All Utilities)			**10.43%**			**9.64%**	**(79)**
Average (Distribution Only)			**9.95%**			**9.37%**	**(57)**
Average (Distribution Only, exc. IL FRP)			**10.29%**			**9.53%**	**(77)**
Average (Vertically Integrated Only)			**10.59%**			**9.73%**	**(86)**
2020							
# of Decisions		**11**					
Average (All Utilities)			**10.28%**			**9.41%**	**(87)**
Average (Distribution Only)			**10.05%**			**9.07%**	**(98)**
Average (Vertically Integrated Only)			**10.47%**			**9.72%**	**(74)**

Source: S&P Global Market Intelligence
Last Updated: 3/13/2020
*** Due to Rounding, the ROE Award is reported as 10.00 on the S&P Global Website.**
‡ S&P incorrectly reports this value as 9.9%
Ω Utility did not file a full rate case, approved ROE based on a settlement
¥ S&P incorrectly reports this value as 10.02%

Calculation of Revenue Requirement Impact of DEP's Proposed ROE vs. National Average ROE for Vertically Integrated Utilities

(1)	Smith Exhibit 1 Page 1	DEP requested rate of return				7.41%
		1) Calculate Rate of Return Using ROE = 9.74%				
		Capital Component	**Percentage of Total**	**Cost**		**Weighted Cost**
(2)	Smith Exhibit 1 Page 2	Long Term Debt	47.00%	4.15%		1.95%
(3)		Member's Equity	53.00%	9.74%		5.16%
(4)	(2)+(3)	**Rate of Return (ROE = 9.74%)**				**7.12%**
		2) Calculate Revenue Requirement Impact at the Proposed ROE vs. National Average				
(5)	Smith Exhibit 1 Page 2	Rate Base ($000)			$	10,859,981
(6)	= (4)	Rate of Return (ROE = 9.74%)				7.12%
(7)	(5) x (6)	Adjusted Income Requirement (ROE = 9.74%)			$	772,705
(8)	Commercial Group Exh. CR-1	DEC Proposed Income Requirement ($000)			$	804,903
(9)	(8) - (7)	Difference in Income Requirement ($000)			$	32,198
(10)	Smith Exhibit 1 Page 2	Conversion Factor				1.3054
(11)	(9) x (10)	**Difference in Revenue Requirement ($000)**			**$**	**42,031**
(12)	Smith Exhibit 1 Page 1	Requested Revenue Requirement Increase ($000)			$	585,961
(13)	(11) / (12)	**Percent of Increase from ROE Increase**				**7.17%**

Class Unitized Rates of Return, DEP Proposed Cost of Service Study

	Present		Proposed	
Customer Class	**ROR**	**UROR**	**ROR**	**UROR**
	(1)	**(2)** **(1) / Total Retail**	**(3)**	**(4)** **(3) / Total Retail**
RES	2.74%	0.83	6.99%	0.94
SGS	2.53%	0.77	6.84%	0.92
SGSCLR	1.57%	0.48	6.12%	0.83
MGS	4.00%	1.21	7.93%	1.07
LGS	3.44%	1.04	7.51%	1.01
SI	8.18%	2.48	11.06%	1.49
TSS	2.35%	0.71	6.71%	0.91
ALS (+SLS for Present)	8.73%	2.65	15.87%	2.14
SLS			6.53%	0.88
SFL	8.49%	2.57	11.29%	1.52
Total Retail	**3.30%**	**1.00**	**7.41%**	**1.00**

Sources:
Pirro Exhibit 4, page 1
E1 Item 45D, page 5

Examination of SGS-TOU and Remainder of MGS Subclass Usage Data

MGS Subclass	DEP Cost of Service Study	DEP Rate Design		Total $ for Rate Design, Energy, DEP Cost of Service Study	Estimated Unit Costs, Energy
	(kWh)	(kWh)		($)	(c/kWH)
	(1)	(2)		(3)	(4)
					(3) / (2)
SGS-TOU	2,807,099,681	8,402,221,509	$	321,011,259	3.82
Remainder:	8,371,865,197	2,798,412,225	$	109,815,019	3.92
MGS		2,766,466,054			
GS-TES		21,819,600			
CH-TOUE		8,724,389			
CSE		1,376,502			
CSG		25,680			
Total	**11,178,964,878**	**11,200,633,734**			

Functional Revenue Per Duke Energy Progress Cost of Service Study Versus Proposed Revenue Recovery

	Revenues at Proposed Rates	Charge Revenue as % of Total Proposed Revenues	Adjustments for Service Rdiers	Adjusted Revenues at Proposed Rates	Remove Current Clause Rider Revenues	Remove New Rider Revenues	Total Base Rate Revenues	Charge Revenue as % of Total Base Rate Revenues	Unit Cost from DEP COSS	Functional Revenue as a % of Cost
	(1)	(2)	(3)	(4) (2) + (3)	(5)	(6)	(7) (4) - (5) - (6)	(8)	(9)	(10)
Customer	$ 9,064,606	1.20%		$ 9,064,606			$ 9,064,606	1.39%	$ 10,877,481	1.67%
Energy	$ 529,002,485	70.02%	$ (29,538,949)	$ 499,463,536	$ 68,263,204	$ (19,493,154)	$ 450,693,486	69.04%	$ 321,011,259	49.19%
Demand	$ 217,430,137	28.78%		$ 217,430,137	$ 24,393,426		$ 193,036,711	29.57%	$ 320,726,952	49.14%
Total	**$ 755,497,228**	**100%**		**$ 725,958,279**	**$ 92,656,630**		**$ 652,794,803**	**100%**	**$ 652,615,692**	**100%**
						Spread Factor	*$ 1,161,891*			
						Total with Spread Factor	*$ 651,632,912*			

Sources:
DEP Response to Commercial Group Data Request No. 1, Item 1-4, Unit Costs 12-31-2018 worksheet
DEP Response to Commercial Group Data Request No. 1, Item 1-7, SGS-TOU worksheet

PLACE: Dobbs Building
Raleigh, North Carolina

DATE: Friday, December 1, 2017

TIME: 9:30 a.m. - 12:30 p.m.

ORIGINAL

DOCKET NO: E-2, Sub 1142

BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

DUKE ENERGY PROGRESS, LLC

Application for Adjustment of Rates and Charges

Applicable to Electric Utility Service

in North Carolina.

VOLUME: 13

Noteworthy
Reporting Services, LLC

TABLE OF CONTENTS

EXAMINATIONS

spend the money for a cap in place, that you would expect to have an improvement of groundwater quality over time. And that simply -- that simply doesn't happen when you have wastes that are saturated. So therefore, you know, is it reasonable to spend the money to cap a surface impoundment knowing that you are going to have continued leaching of constituents to the groundwater, just like you do now, even before the cap? Doesn't seem like a reasonable action plan, and the efficiency of the money -- or the effectiveness of the money spent for a remedial measure, long term.

MR. QUINN: No more questions. Thank you.

CHAIRMAN FINLEY: All right. Questions by the Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Quarles, this may be in the materials, but you're probably more familiar with it than I am, so I will ask you the question.

The specific design of the closure plant at Roxboro and Mayo, does that include any engineered elements to divert groundwater flow -- future groundwater flows from upgradient?

A. It does not. There is nothing to prevent that lateral flow of groundwater.

Q. Thank you.

A. The other thing that I might add, as it relates to Roxboro, is the east impoundment -- or the east basin has an engineered landfill on top of the original ash impoundment, and that landfill has a liner and leachate collection system that is collecting this leachate that would otherwise infiltrate into the ground. What is interesting is that they take that leachate from that dry landfill on top of these basin and put that same leachate into the unlined basins of the east and west. So in the effort of protecting groundwater from this dry landfill on top of the east basin, they take that leachate and put it into unlined surface impoundments.

CHAIRMAN FINLEY: Ms. Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Good morning. Going back historically, when a location would be agreed upon for a plant, they would have considered the ability for storage and how the ground would receive that, et cetera; was there a thinking in the science of it at the time, that that was addressing safety issues?

A. You know, when I look at historical

documents, it's interesting, the industry recognized the likelihood that these ponds would leak, and they also recognized that -- that constituents, such as arsenic, for example, were harmful to people and were harmful to fish and aquatic life. So, on one hand, they recognized the risk, but they also seemed to accept that that's the way that they are going to do it, and I can't answer or explain why, but that seems to be very common in the files that I have reviewed.

Q. And that's on the behavior of the power companies, right?

A. Correct.

Q. But beyond that, in academia and the scientific world, was there discussion -- are you aware of any discussion and study about those issues back when the unlined ponds were the standard state-of-the-art method?

A. Well, the 1988 report to Congress by the EPA was, you know, very good at talking about what the industry practices were, and I could -- it talked to how -- we had groundwater protection standards back then, and the report -- the EPA report talked about that, and how common it was that there would be an exceedance of a standard -- one or more standards at several power plants around the country. So they recognized the risk, but it -- I'm not aware of any other, you know, formal studies in the waste industry in the 1970s. The power industry has Utility Solid Waste Activity Group, what's called USWAG, which was an industry group where they studied different types of things, and there might have been an earlier report that I did not have access to that would talk about that.

Q. Are you aware in any literature or any study, outside of that, that the power companies did or that they paid for, that looked at or examined whether the unlined ponds were, in and of themselves, a safety tool?

A. I am aware of -- I'm aware of an industry report that was published in 2001 by the Electric Power Research Institute, EPRI. It is really a telling report, as it relates to the plan of cap-in-place, because it evaluated -- and this is an industry document -- it evaluated three different disposal sites that were unlined surface impoundments that were all capped in place. And it evaluated the effectiveness of the cap in place to improve groundwater quality . And one of them -- one cap in place did not result in any improvement of groundwater quality. And the unique characteristic of that site is that the ash was submerged in groundwater. All right. And so they concluded that the cap was, quote, unquote, a cap that had little or no effect on this process. Again, falling back to what I said in my direct testimony about the lateral inflow of groundwater, and then if you have 10s of feet of ash that's saturated, that cap is not going to result in improvement of the groundwater quality.

Q. What I'm trying to get at is, was there a time when -- when the knowledgeable people, the academia and the professors, those types, accepted that an unlined pond was, to some degree, a safety measure, and that that -- and then there was a theory supporting that, believing that it was, and then there was a point in time when, perhaps, that theory fell away or was disproven; is there any such thing as that?

A. No. I'm not aware of any industry documents or any EPA documents at that time. The only thing that I would say to that is that, clearly, the industry recognized a risk to groundwater contamination in the mid-'70s, otherwise, they wouldn't have changed their way of disposal, preferring the dry landfill as opposed to wet impoundment.

Q. So there was a change in advancement and knowledge that prompted -- as we do with everything, as we learn, we make changes; as we advance, we make changes; as we become better capable of doing certain things, we make changes; is that fair?

A. Yeah. That's fair to say too. And I think what I have kind of gathered in my years of reviewing thousands of files -- you know, state agency files, EPA files, discovery files, that sort of thing, is that sometimes you tend to not choose to line an impoundment or build a lined landfill if there is no regulation that requires you to do so, and you proceed, kind of, at your own risk, if you will. That was fairly common.

Q. All right. So from your testimony, you are indicating that excavation will, at some point in time, reduce or prevent the further contamination or reduce the contamination that exists?

A. That's correct.

Q. So at what point in time -- if we were to begin excavation, at what point in time would we see the benefit on both counts, prevention and reduction; how long would it take?

A. I have read reports of some instances where there has been post-excavation monitoring in the Carolinas, the east coast, related work from the Southern Environmental Law Center, where it talked about fairly quick improvement of groundwater quality after the excavation, removal, and safe disposal of the waste.

Q. When you say fairly quick, I assume some sort period of time?

A. I would say -- and I don't know the specific time frame, but it's certainly within months or years, because these excavations were just recently performed.

Q. So months or a few years?

A. As opposed to decades of --

Q. Would it be significant improvement during those early -- the early stage?

A. You would expect -- of course, there is a groundwater flow velocity that's associated with this, so there is contaminated groundwater that is already going to be beneath these basins that's going to have to take its natural flow direction towards the receiving stream, but when you remove that source of the contamination, you can only expect that the quality will improve.

Q. What do we know or what do you know about the -- during the process of removal, what happens to contamination as the excavation process is being carried out?

A. The contamination of the groundwater?

Q. That, as well as safety to human and animal life, et cetera, plant life.

A. So the safety -- when you excavate the material, you are going to take it -- or the utility will take it to a lined disposal unit, whether it's on site or off site. So therefore, it would be designed to be protective of groundwater. So when you remove that source of the contamination, now you have a reduction of the concentrations, because groundwater from upgradient directions is naturally going to flow beneath what used to be the surface impoundment on the way to the stream. So over time, there would be some interaction and dilution, if you will, of that groundwater that is interacting with the contamination that's underneath the surface impoundment.

Q. Would the excavation process, itself, cause any worsening of the contamination situation?

A. It shouldn't.

Q. The disturbing of the material, of the groundwater, of the surface water?

A. So if you have ash that's submerged in groundwater, you are going to have to dewater that ash to be able to excavate the ash. So then that dewatering process will require a certain degree of treatment of that water before it's discharged to wherever it's going, whether it's going to go to a receiving stream or to a wastewater treatment plant, for example. So to be fully protective of surface waters, you would need to ensure that the quality of the water that is being pumped out of the -- what used to be the old impoundment would meet the appropriate standards for water quality and discharge to a surface water.

Q. What do you know about the Company's decision to cap in place? Did you do any further study into the reasons they chose that?

A. I didn't, other than I know that they planned to cap in place, and they only planned to pump or remove just a small amount of water, as needed, to operate construction equipment and/or dewater the surface so that they could build a cap. That's the limit -- that was -- their closure plan was pretty basic.

Q. All right. But your look into this and your study was more from a distance, rather than interaction with the Company or understanding from their perspective?

A. Correct.

Q. All right. Thank you.

EXAMINATION BY CHAIRMAN FINLEY:

Q. Mr. Quarles, is boron a naturally-occurring element in the soils in places like Mayo and Roxboro?

A. Boron is naturally occurring, just like most, if not all, metals. They do naturally occur. And what's -- so the challenge, when you look at a closure process, or whether or not there is a groundwater contamination, is you have to you understand what is naturally occurring and what is not. So there is ways to look at whether or not the boron, or arsenic, or whatever is naturally occurring or related to leaching from the waste. So one process is to look at the upgradient wells in -- compared to the downgradient wells. And if it's naturally occurring, there is an opportunity for boron, or arsenic, or whatever to be in the upgradient wells.

So, you know, what I do is I evaluate that, but you have to be careful sometimes, because the upgradient wells -- let's recognize, these impoundments have been in operation for, what, 40, 50, 60 years. And so when you sluice water to an impoundment, it mounds the groundwater and creates a radial flow, and so part of that, if a well is on the upgradient side, in fact, could have been influenced and might be influenced by that mounding to have some of these leachable constituents in it.

But what we do is we could also look at other constituents to, kind of, look for the signature of whether or not the metals that naturally occur are indicative of coal ash. So I look at other things like sulphate, calcium. These are the things that, again, commonly occur, but they also -- there is a relationship many times between a concentration of boron and a concentration of sulphate.

Q. You mentioned the Electric Power Research Institute study. What was the date of that again?

A. 2001.

Q. Do you know the name of it?

A. Yeah. I think so.

(Witness peruses documents.)

It's called "Evaluation and Modeling of Cap Alternatives at Three Unlined Coal Ash Impoundments." This date is September 2001.

Q. My understanding is, of the sluicing process that you mentioned, that coal ash is transported from the generator, to the pond, to the impoundment, or the repository, whatever you want to call it, and the coal ash settles to the bottom, and the water on the top is discharged; is that right?

A. Yeah. And so the reason utilities sluice is to take an ash that's created at the boiler, then mix it with water, and then they pump it to a pond so that the solids can settle out, and then the water, some of it will evaporate, some of it seeps into groundwater, and then some of it overflows through a permitted, regulated what we call an outfall to a receiving stream.

Q. Is a technical name for the water that is discharged --

A. We call it effluent.

Q. It's been in different contexts. Effluent means one thing to me and wastewater means another thing to me. Is it sometimes called wastewater as opposed to effluent?

A. It's really kind of synonymous here, because actually, the water that's being discharged through a permitted outfall includes a lot more than just loose water. It could be miscellaneous lab waste, and floor drains, and truck washing areas, and that sort of thing.

Q. But within the people of expertise like you, sometimes that water is described interchangeably as effluent and wastewater?

A. Correct.

Q. I think there is another witness in the case that says that any landfall -- or landfill -- and I take that to mean a lined landfill as well as an unlined landfill - will leak; do you agree with that?

A. There is a potential for any landfill to leak, whether it's lined or not. And, you know, mistakes can happen during construction with even a composite-lined landfill. So they are not foolproof, but they are better than no liner at all.

Q. All right. Thank you.

EXAMINATION BY COMMISSIONER GRAY:

Q. Mr. Quarles, in your summary, you referred to the Kingston coal plant TVA issue.

What was the remediation taken on that facility?

A. It's a little bit different, in that it was a dike failure of an impoundment. So we ended up with ash in the river and ash floating downstream. And so the remediation there was to excavate that material. And most of it, I believe, was transported off site by rail to a landfill in Alabama.

Q. Is the TVA a federal agency?

A. It is.

Q. Who paid for the cleanup?

A. I don't know.

Q. Who would you think would have paid for it?

A. You know, I don't know if it came out of their operating budget, I don't know if they filed for an insurance claim, I don't know if they went for ratepayer reimbursement. I just don't know.

Q. Do you know how much it cost?

A. I don't.

Q. Thank you.

CHAIRMAN FINLEY: Questions on the Commission's questions?

EXAMINATION BY MR. RUNKLE:

Q. In a follow-up of Commissioner Brown-Bland's questions about when a utility may have known that there were better, less environmental -- there were better ways to handle the coal ash than the wet coal ash in an unlined landfill; do you remember those questions?

A. I do.

Q. Now, if a utility, like DEP, would -- knew or should have known sometime in the '70s, or in the '85 -- the '88 report, or 2001 time period, why would a utility, like DEP, continue with the wet, unlined landfills?

MR. BURNETT: Objection, Mr. Chairman. Calls for speculation.

CHAIRMAN FINLEY: Do you have an opinion on that?

THE WITNESS: I guess my opinion would be it's convenient and there is no regulatory standard saying they can't do that.

EXAMINATION BY MR. DROOZ:

Q. Mr. Quarles, you were asked about how long it would take after excavation of ash for contamination to resolve or disappear.

Is that -- is the answer to that question something that's gonna vary from site to site?

A. It is.

Q. If there is a groundwater plume that has gone beyond the compliance boundary and has a significant amount of constituent concentration and it's well above the allowed amount, will the time it takes to remediate be greater than if there is a small amount?

A. It is. The further it's migrated away, and the higher the concentration is, one would expect a longer time.

Q. And if there is a significant plume of contaminants off site, are there methods to help remediate that above and beyond just excavation?

A. There are technologies out there that you could use to capture and prevent that groundwater from flowing off site.

Q. Would extraction wells and treatment be one of those technologies?

A. That's certainly one of the technologies that's being used.

Q. Are there grout curtains or other technologies?

A. There are, yes.

Q. Thank you. That's all.

EXAMINATION BY MR. BURNETT:

Q. Mr. Quarles, what year was the federal Coal Combustion Residuals rule passed?

A. I don't remember the exact year, but it's two or three years ago.

Q. Okay. Recently, correct?

A. Recently, correct.

Q. And it's not your testimony that the passage of that CCR rule was the first time that the federal EPA discovered that utilities in the nation were using unlined wet ash basins, is it?

A. That's not the first discovery, correct.

Q. That's right. In fact, you just testified here that the EPA at least was studying the issues of CCRs and their impact on the environment as early as 1988, correct?

A. Correct.

Q. You'd also agree with me, though, that the EPA, while it may have been studying the impact of CCRs in the 1980s, it took definitive action to comprehensively regulate them, as you said, maybe as early as three years ago, maybe even sooner than that, correct?

A. Yeah. The Kingston spill was the trigger, if you will, that caused a more comprehensive review of disposal units around the country, in terms of dike stability and contamination potential.

Q. And I believe I just heard you say, in response to another question, an answer that makes me believe that you are not asserting that wet, unlined ash basins have been illegal or unauthorized in this country, correct?

A. You know, I'm not a lawyer, so I don't like to, you know, talk about legality of a surface impoundment. All I can say is that a recent case that I worked on in Nashville, U.S. District Court against TVA at the Gallatin facility, the judge ruled that the unlined surface impoundment was, in fact -- points were discharged to water of the state.

Q. That's right. But that judge is not the EPA, is he?

A. He's not.

Q. Yeah. What year was the Coal Ash Management Act passed in the state of North Carolina?

A. I don't know.

Q. Well, do you believe that, whatever year that was, that's the first time that the State of North Carolina or the North Carolina Department of Environmental Quality knew that there were unlined wet ash basins in the state?

A. I can't comment on that. Just purely speculating.

Q. Would that have been something that you might

have wanted to look into before you testified today?
A. My scope of work was to really look at the practices relative to closure and performance standard, whether or not it met the federal CCR rule, which is the federal standard that the states are required to be at least as stringent as that.
Q. Okay. Thank you, sir.
MR. QUINN: Briefly, Mr. Chairman.
EXAMINATION BY MR. QUINN.
Q. My understanding is that the federal CCR rules came into effect in 2014; does that sound about right?
A. That sounds about right.
Q. Prior to 2014, were there any regulations on the way in which coal ash can be stored, that you are aware of?
A. You know, every state -- every state has an opportunity to regulate coal combustion waste. Like in the state of Tennessee, for example, they formalized, in the solid waste rules -- permit by rules for disposal of coal combustion waste. So for years there has been a regulation in place for the method. Now, recognizing that -- after the Kingston spill, they recognized that, perhaps, that wasn't stringent enough,

and so they changed that and started requiring all disposal units to be, essentially, equivalent to what we call Subtitle D, which is a composite liner, leachate collection system, that sort of thing. So individual states may have had an opportunity to regulate, but there was no formal federal standard for which the states had to go by.

Q. So if there are no formal federal standards the states had to go by, is it fair to say, then, that compliance with industry standard is what the utility's duty is when is comes to storage of coal ash?

A. That's a fair statement.

Q. And you have testified prior about what industry standard was at that time, correct?

A. Correct.

Q. Okay. Additionally, do you know whether the CCR rules at the federal level were finalized only after a lawsuit against the EPA that it comply with its duties to regulate coal ash; do you have any knowledge of that?

A. No, I don't.

Q. Okay. You were also asked about whether or not you reviewed North Carolina's Coal Ash Management Act; do you recall that?

A. I do.

Q. Now, whether or not there is a North Carolina Coal Ash Management Act, Duke Energy Progress is still required to comply with the federal standards, the CCR rules, right?

A. Correct.

MR. BURNETT: Objection, Mr. Chairman. The witness testified he's not a lawyer, and Counsel is testifying with this line of questioning.

MR. QUINN: Mr. Quarles is an expert in the area of the management of coal ash. He is very familiar with the standards, as he's testified at the federal level. I think he can give an opinion on that issue.

CHAIRMAN FINLEY: He may give his expert but nonlegal opinion, if he has one.

BY MR. QUINN:

Q. Mr. Quarles --

CHAIRMAN FINLEY: Is there a question pending?

MR. QUINN: Yeah. Well, I'm gonna rephrase the question, just to make sure we clear up any issues.

BY MR. QUINN:

Q. In your experience as a geologist working with coal ash, do utilities -- do utilities have to comply with the federal CCR rules?

A. They do. And, in fact, they are making plans to comply right now. So their regulatory deadlines, one of which is development of the closure plans, and put them on publicly-available websites, and constructing sampling, growing, and monitoring programs, doing liner assessments, you know, to determine whether these surface impoundments are lined or not. So the wheels are turning, and the regulatory deadlines are -- you know, they are happening for sure.

Q. Mr. Quarles, I'm sure you are also familiar that there are groundwater standards that dictate that certain, say, boron, arsenic, whatever, cannot go above certain minimum standards in groundwater; are you aware of that?

A. I am.

Q. Okay. Now, whether or not there are -- there is a coal ash-specific rule prior to 2014, are utilities required to comply with those rules?

A. Groundwater protection standards have been around for as long as I have, you know, been in this business, since the mid-'80s. I mean, there is nothing new. In fact, the 1988 report talked about how it was common that groundwater protection standards were exceeded at coal combustion waste sites. So standards have been there, whether or not there is a formal regulation on how you are supposed to design, construct, and operate a disposal unit. There has still been the requirement that you have groundwater protection standards that are meant to protect human health in the environment.

Q. In your review of documents in preparation for your testimony, did you review any groundwater monitoring studies commissioned by Duke Energy Progress?

A. The -- no. The studies that I reviewed really were the comprehensive site assessments, which were comprehensive site assessments that were done on behalf of Duke Progress, I guess, in accordance with the CAMA requirements. And -- so they were good discussions where their consultants made the conclusions on what constituents exceeded standards or not.

Q. And those are site-specific, right, to Roxboro and Mayo?

A. They were.

Q. Okay. And in those comprehensive site assessment studies, were any exceedances of groundwater standards found?

A. There were.

Q. And the exceedances, were they for constituents of coal ash?

A. They were.

Q. And were they downgradient from the coal ash impoundments? In other words, were they -- if the groundwater was flowing in one direction, are they downgradient from the coal ash impoundment, such that the water would have flowed --

MR. BURNETT: Mr. Chairman, objection. Asked and answered, and also well beyond the scope of cross examination. Counsel, I believe, is just putting this witness now on a direct format, notwithstanding his previous testimony.

CHAIRMAN FINLEY: Well, I asked him about that, and he testified about it, and I think that is consistent with the questions by the Commission, so you may answer.

THE WITNESS: So the comprehensive site assessments were done by the independent consultant specific to each of the sites, and they were -- their conclusions were that coal combustion waste constituents were, in fact, in the groundwater migrating from the disposal units, and I agree with those conclusions.

MR. QUINN: No further questions.

CHAIRMAN FINLEY: We will, without objection, accept Mr. Quarles' exhibits into evidence, and you may be excused.

THE WITNESS: Thank you.

MR. QUINN: Thank you, Mr. Quarles.

(Whereupon, Quarles Exhibits 1 through 6 and 8 through 10 were admitted into evidence.)

CHAIRMAN FINLEY: NCJC witness is next.

MS. LUHR: North Carolina Justice Center, North Carolina Housing Commission, Natural Resources Defense Council, and Southern Alliance for Clean Energy calls Satana Deberry to the stand.

SATANA DEBERRY,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION BY MS. LUHR:

Q. Please state your name and business address

DUKE ENERGY PROGRESS
Docket No. E-2, Sub 1219

Rate of Return and Index
Summer Coincident Peak Method
Test Year Ending December 31, 2018

		Present Rates		Company Proposed Rates	
Line	Rate Class	Rate of Return	Index	Rate of Return	Index
		(1)	(2)	(3)	(4)
1	Rate RES	2.7%	83	7.0%	94
2	Rate SGS	2.5%	77	6.8%	92
3	Rate SGSCLR	1.6%	48	6.1%	83
4	Rate MGS	4.0%	121	7.9%	107
5	Rate LGS	3.4%	104	7.5%	101
6	Rate SI	8.2%	248	11.1%	149
7	Rate TSS	2.4%	71	6.7%	90
8	Rate ALS,SLS	8.7%	264	11.5%	155
9	Rate SFL	8.5%	257	11.3%	152
10	Total NC Retail	3.3%	100	7.4%	100

Source: Pirro Exhibit No. 4 (Corrected), page 1 of 3

DUKE ENERGY PROGRESS
Docket No. E-2, Sub 1219

Company Proposed Increase by Rate Class
Summer Coincident Peak Method
Test Year Ending December 31, 2018

Line	Rate Class	Present Revenue with Existing Riders[1] (000)	Proposed Revenue with Existing Riders (000)	Company Proposed Increase/(Decrease) Amount[2] (000)	Company Proposed Increase/(Decrease) Percent	Proposed Revenue with Existing & New Riders (000)	Company Proposed Increase/(Decrease) Amount[3] (000)	Company Proposed Increase/(Decrease) Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate RES	$ 1,877,330	$ 2,217,577	$ 340,247	18.1%	$ 2,148,103	$ 270,772	14.4%
2	Rate SGS	234,951	275,793	40,842	17.4%	267,411	32,461	13.8%
3	Rate SGSCLR	4,262	4,978	716	16.8%	4,843	581	13.6%
4	Rate MGS	962,327	1,083,911	121,584	12.6%	1,057,840	95,514	9.9%
5	Rate LGS	549,930	617,801	67,871	12.3%	604,484	54,554	9.9%
6	Rate SI	5,869	6,476	607	10.3%	6,302	433	7.4%
7	Rate TSS	566	647	81	14.4%	632	66	11.7%
8	Rate ALS,SLS	92,840	106,826	13,986	15.1%	102,059	9,219	9.9%
9	Rate SFL	220	247	27	12.2%	240	19	8.7%
10	Total NC Retail	$ 3,728,295	$ 4,314,256	$ 585,961	15.7%	$ 4,191,913	$ 463,619	12.4%

Source:

[1] Pirro Exhibit No. 4, page 1 of 3, column (J)
[2] Pirro Exhibit No. 4, page 1 of 3, column (I)
[3] Pirro Exhibit No. 4, page 1 of 3, column (N)

DUKE ENERGY PROGRESS
Docket No. E-2, Sub 1219

Rate of Return and Index
Winter Coincident Peak Method
Test Year Ending December 31, 2018

		Present Rates		Company Proposed Rates	
Line	Rate Class	Rate of Return	Index	Rate of Return	Index
		(1)	(2)	(3)	(4)
1	Rate RES	1.2%	33	6.0%	77
2	Rate SGS	3.0%	83	7.3%	94
3	Rate SGSCLR	1.6%	45	6.3%	81
4	Rate MGS	8.4%	235	11.3%	146
5	Rate LGS	10.6%	297	12.9%	167
6	Rate SI	10.9%	305	13.2%	170
7	Rate TSS	2.3%	65	6.8%	88
8	Rate ALS,SLS	8.7%	245	11.6%	150
9	Rate SFL	8.5%	238	11.4%	148
10	Total NC Retail	3.6%	100	7.8%	100

DUKE ENERGY PROGRESS
Docket No. E-2, Sub 1219

Company Proposed Increase by Rate Class
Winter Coincident Peak Method
Test Year Ending December 31, 2018

Line	Rate Class	Present Revenue with Existing Riders (000)	Proposed Revenue with Existing Riders (000)	Company Proposed Increase/(Decrease) Amount (000)	Company Proposed Increase/(Decrease) Percent	Proposed Revenue with Existing & New Riders (000)	Company Proposed Increase/(Decrease) Amount (000)	Company Proposed Increase/(Decrease) Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate RES	$ 1,892,109	$ 2,322,151	$ 430,042	22.7%	$ 2,252,677	$ 360,568	19.1%
2	Rate SGS	236,037	275,977	39,941	16.9%	267,596	31,560	13.4%
3	Rate SGSCLR	4,280	5,016	735	17.2%	4,881	600	14.0%
4	Rate MGS	967,534	1,039,820	72,286	7.5%	1,013,750	46,215	4.8%
5	Rate LGS	559,424	587,137	27,714	5.0%	573,820	14,396	2.6%
6	Rate SI	5,890	6,329	439	7.5%	6,154	264	4.5%
7	Rate TSS	569	653	84	14.8%	638	69	12.1%
8	Rate ALS,SLS	93,383	108,075	14,692	15.7%	103,308	9,925	10.6%
9	Rate SFL	222	250	28	12.8%	243	21	9.2%
10	Total NC Retail	$ 3,759,447	$ 4,345,409	$ 585,961	15.6%	$ 4,223,066	$ 463,619	12.3%

DUKE ENERGY PROGRESS
Docket No. E-2, Sub 1219

Rate of Return and Index
Summer/Winter Peak Method
Test Year Ending December 31, 2018

		Present Rates		Company Proposed Rates	
Line	Rate Class	Rate of Return (1)	Index (2)	Rate of Return (3)	Index (4)
1	Rate RES	1.8%	54	6.4%	84
2	Rate SGS	2.8%	80	7.1%	93
3	Rate SGSCLR	1.6%	46	6.2%	82
4	Rate MGS	6.1%	177	9.6%	126
5	Rate LGS	6.6%	191	9.9%	131
6	Rate SI	9.5%	277	12.1%	160
7	Rate TSS	2.3%	68	6.8%	89
8	Rate ALS,SLS	8.7%	254	11.5%	152
9	Rate SFL	8.5%	247	11.4%	150
10	Total NC Retail	3.4%	100	7.6%	100

DUKE ENERGY PROGRESS
Docket No. E-2, Sub 1219

Company Proposed Increase by Rate Class
Summer/Winter Peak Method
Test Year Ending December 31, 2018

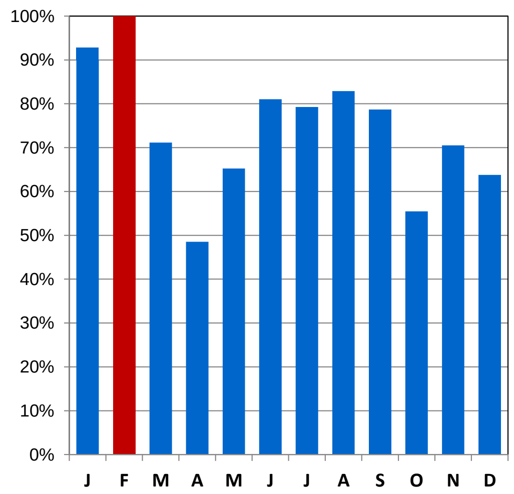
Line	Rate Class	Present Revenue with Existing Riders (000)	Proposed Revenue with Existing Riders (000)	Company Proposed Increase/(Decrease) Amount[2] (000)	Company Proposed Increase/(Decrease) Percent	Proposed Revenue with Existing & New Riders (000)	Company Proposed Increase/(Decrease) Amount[3] (000)	Company Proposed Increase/(Decrease) Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate RES	$ 1,892,109	$ 2,280,198	$ 388,089	20.5%	$ 2,210,724	$ 318,615	16.8%
2	Rate SGS	236,037	276,398	40,362	17.1%	268,017	31,981	13.5%
3	Rate SGSCLR	4,280	5,007	726	17.0%	4,871	591	13.8%
4	Rate MGS	967,534	1,062,852	95,318	9.9%	1,036,782	69,247	7.2%
5	Rate LGS	559,424	605,899	46,475	8.3%	592,582	33,158	5.9%
6	Rate SI	5,890	6,407	518	8.8%	6,233	343	5.8%
7	Rate TSS	569	652	83	14.6%	637	68	11.9%
8	Rate ALS,SLS	93,383	107,745	14,363	15.4%	102,978	9,596	10.3%
9	Rate SFL	222	250	28	12.5%	242	20	8.9%
10	Total NC Retail	$ 3,759,447	$ 4,345,409	$ 585,961	15.6%	$ 4,223,066	$ 463,619	12.3%

Exhibit NP-4

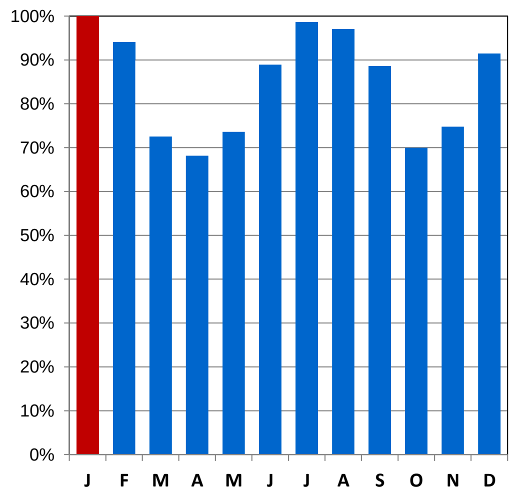
Duke Energy Progress

Monthly Peaks as a Percent of System Peak
for Years 2015 through 2019

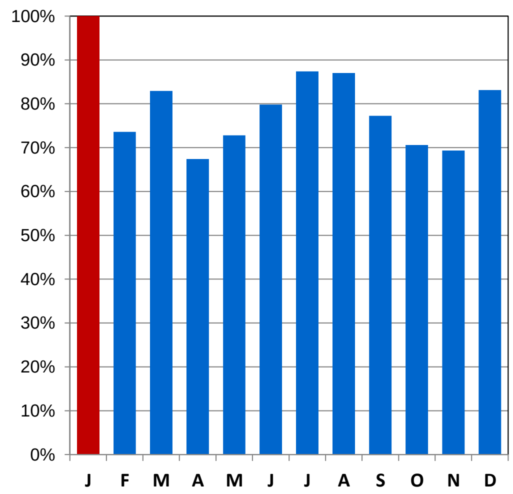
2015



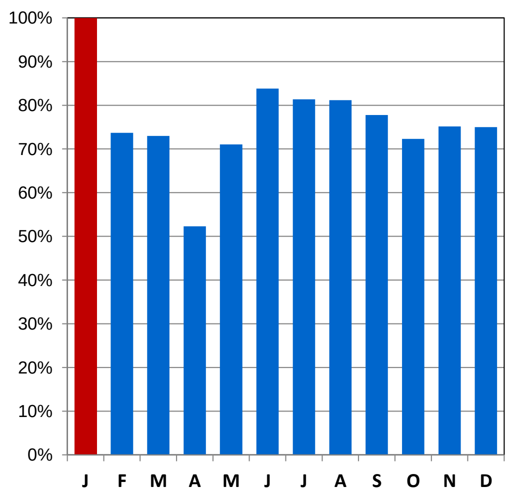
2016



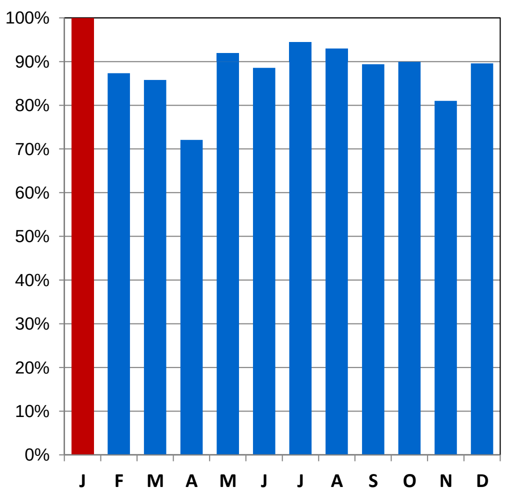
2017



2018



2019

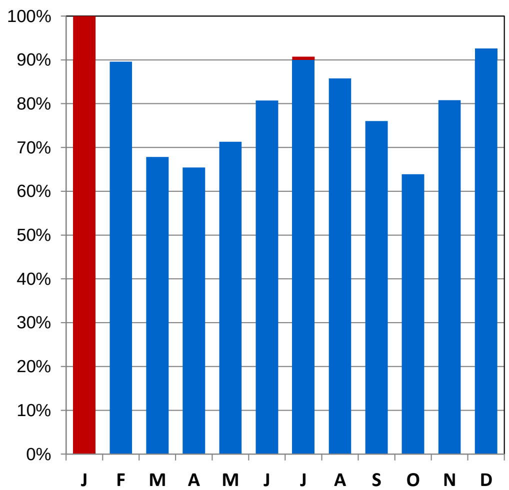


Source:
FERC Form No. 1, Page 401b for years 2015 - 2018.
CIGFUR II DR 1-12 for 2019.

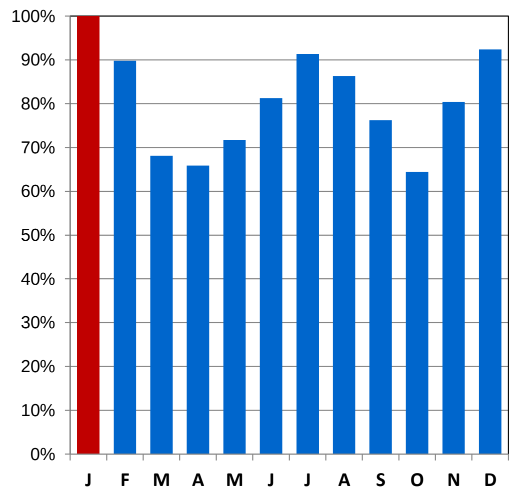
Duke Energy Progress

Monthly Peaks as a Percent of System Peak
Forecasted for Years 2020 through 2024

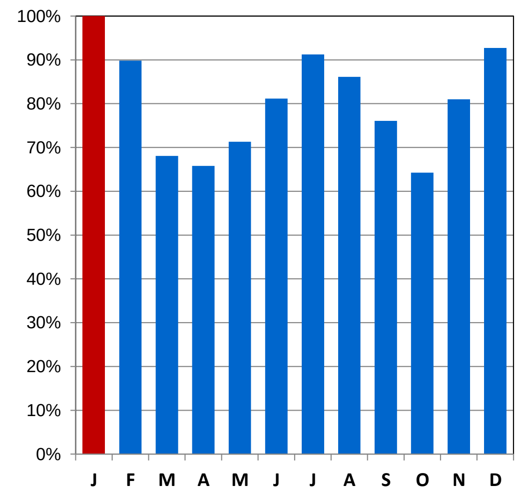
2020



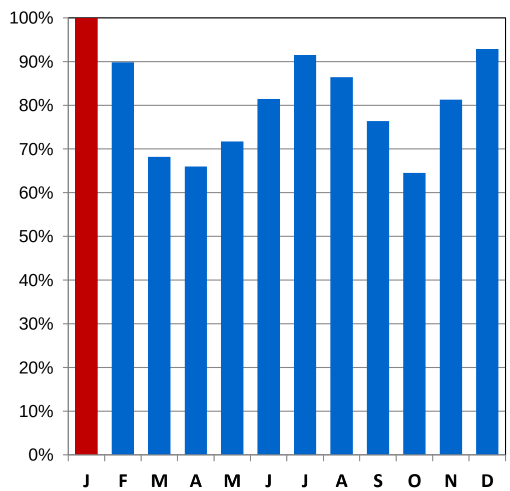
2021



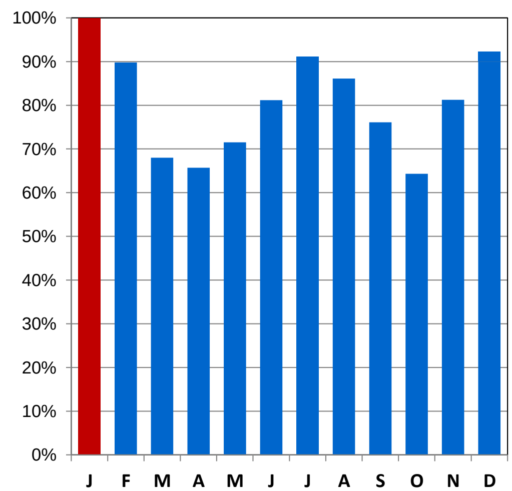
2022



2023



2024



System Peak

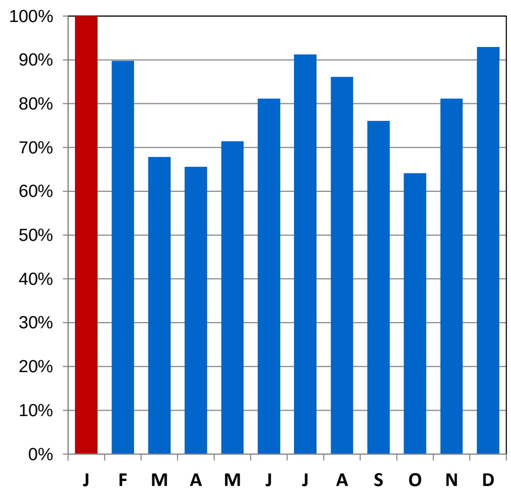
Source:
CIGFUR II DR 1-13

Exhibit NP-5
Page 2 of 2

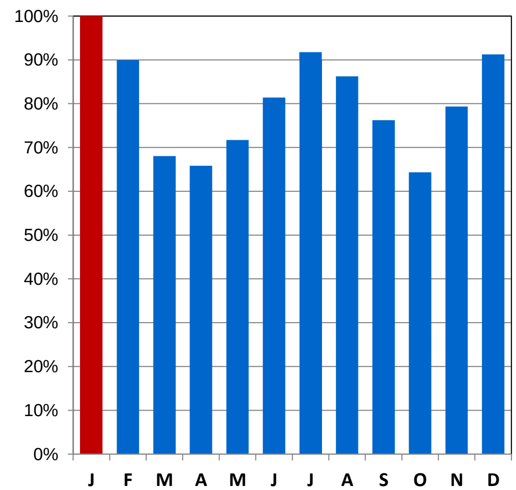
Duke Energy Progress

Monthly Peaks as a Percent of System Peak
Forecasted for Years 2025 through 2029

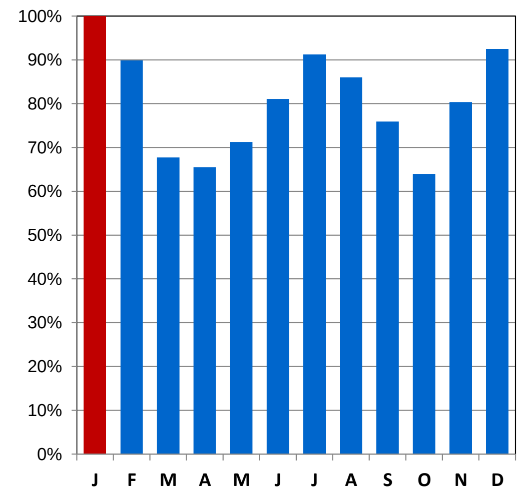
2025



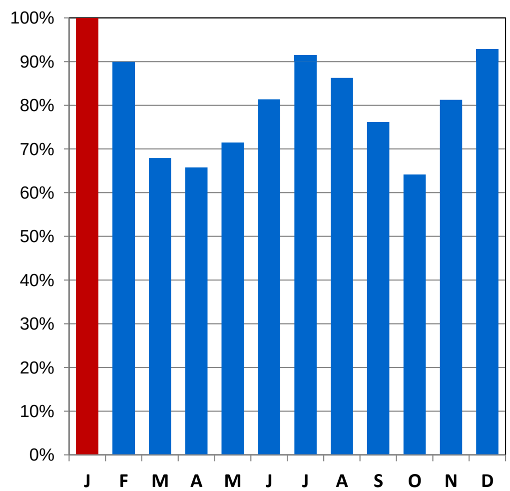
2026



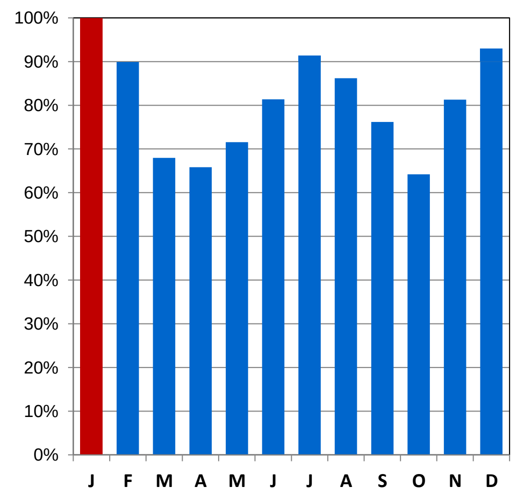
2027



2028



2029



System Peak

Source:
CIGFUR II DR 1-13

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-1

Brunault Resume and Record of Testimony

GDS Associates, Inc
ENGINEERS & CONSULTANTS

GARY D. BRUNAULT

Principal

I/A

EDUCATION

Bachelor of Science, Civil Engineering, Tufts University, Medford, MA, 1979

EXPERIENCE

Mr. Brunault has over 35 years of electric utility consulting experience, serving primarily joint action municipal power agencies. Gary started his career in the early 1980's and was involved in the start-up phases of operations for North Carolina Eastern Municipal Power Agency, North Carolina Municipal Power Agency Number 1, and Piedmont Municipal Power Agency, collectively representing 61 municipal utilities in the Carolinas. Gary has provided consulting services to these and other municipal and cooperative clients ranging from power supply planning, municipal bond finance, wholesale electric cost of service and rates, risk analysis, contract negotiations, regulatory and litigation support.

More specifically, Mr. Brunault has provided consulting engineering services in the following areas:

- Evaluation of responses to RFPs for power supply, and contract negotiations
- Generating asset valuation, strategic portfolio analysis
- Probabilistic analysis related to generating asset decisions
- Preparation of economic analyses to support sale of nuclear and coal-fired generating assets
- Long-term projections of wholesale power supply costs
- Wholesale rate development and implementation of rate structure changes
- Negotiation support for development of (investor-owned utility) production and transmission cost of service formulas (and auditing of the implementation of such formula rates)
- Analysis of wholesale customer impacts of investor-owned utility mergers and settlement agreements
- Testimony in state utility commission proceedings related to municipal utility matters
- Support of jointly-owned coal and nuclear generation project agreements and contract amendments
- Litigation support related to contract interpretation disputes
- Nuclear decommissioning planning and funding policy development
- Consulting Engineer reports for Official Statements in connection with the issuance of municipal revenue bonds and preparation of Annual Engineering Reports supporting Bond Resolution requirements
- Regulatory support of various municipal and cooperative wholesale customer interventions at the FERC
- Strategic planning / scenario planning

Recent Project Experience

Since joining GDS in October 2012, Mr. Brunault has expanded his services in the rates and regulatory areas. Recent projects where Gary has had significant lead responsibilities include:

- Represented Piedmont Municipal Power Agency in settlement discussions conducted in FERC Docket No. EL17-83 regarding the treatment of certain regulatory assets under Duke Energy Carolinas' production formula rate
- Advisor to confidential client in support of a potential generating asset sale in connection with rebalancing and diversifying its portfolio of power supply resources

- Support of successfully negotiated settlement agreement recently filed with the FERC (Docket Nos. EL16-29 and EL16-30) as a result of a complaint filed by wholesale customers of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) seeking a just and reasonable return on common equity under DEC's and DEP's Joint OATT for transmission service
- Key advisor to North Carolina Eastern Municipal Power Agency on the sale of 700 MW of nuclear and coal-fired generating assets to Duke Energy Progress and associated development of a replacement full requirements power purchase agreement, which involved detailed economic analysis and assessment of risks of the overall transaction
- Annual reviews of investor-owned utility production and transmission formula rates under FERC jurisdiction and resolution of challenges on behalf of wholesale customers
- Expert witness on behalf of the Office of Public Counsel before the Florida Public Service Commission regarding the determination of Fair Value of the Power Purchase Agreement between Florida Power & Light and Cedar Bay Generating Company (Docket No. 150075-EI)
- Lead on successful negotiations with Duke Energy Carolinas and Duke Energy Progress to lower the transmission loss factors reflected in the Duke Joint OATT, on file at the FERC (Docket No. ER16-2123) on behalf of wholesale customers
- Represented wholesale customers of Duke Energy Progress in successfully negotiating resolution of recovery of DEP's recovery of cancelled Harris nuclear plant investment culminating in FERC Docket No. ER16-2729
- Engagement with wholesale customers of Entergy Arkansas and Entergy Mississippi supporting their intervention in FERC Docket No ER16-227 to scrutinize Entergy Services' updated depreciation rates for transmission plant and general plant investment accounts for each of the various Entergy Operating Companies
- Testimony on behalf of a wholesale customer potentially affected by the proposed acquisition of Westar by Great Plains Energy in FERC Docket No. EC16-146
- Assessment of potential impacts on wholesale customers of Duke Energy Progress regarding DEP's potential rate recovery of costs incurred to comply with EPA's Coal Combustions Residual rule and North Carolina's Coal Ash Management Act of 2014
- Support of wholesale customers' intervention in FERC Docket No. ER13-1313 regarding Duke Energy Progress's depreciation rate study and associated treatment of cost recovery of un-recovered investment in early-retired coal units

GDS Associates, Inc., October 2012 – Present
Principal and Managing Director of Orlando Office

SAIC Energy, Environment, and Infrastructure, LLC, August 2009 – October 2012
Senior Program Manager

R. W. Beck, Inc., September 1981 – August, 2009
Principal

Record of testimony submitted by Gary D. Brunault:

1. Affidavit Dated December 5, 2019
   Federal Energy Regulatory Commission, Docket No. EL20-4-000
   In Support of Complaint Seeking Reduction in the 11% Return on Common Equity
   under the Full Requirements Power Purchase Agreement with Duke Energy Progress,
   on behalf of North Carolina Eastern Municipal Power Agency

2. Affidavit Dated September 22, 2016
   Federal Energy Regulatory Commission, Docket No. EC16-146-000
   In the Matter of Joint Application of Great Plains Energy Inc. and Westar Energy, Inc.
   for approval of Merger and Disposition of Assets
   on behalf of Kansas Electric Power Cooperative

3. Direct Testimony Dated June 8, 2015
   Florida Public Service Commission, Docket No. 150075-EI
   In the Matter of Petition for Approval of Arrangement to Mitigate Impact of Unfavorable Cedar
   Bay Power Purchase Obligation, by Florida Power & Light Company,
   on behalf of the Citizens of the State of Florida, Office of Public Counsel

4. Rebuttal Testimony Dated July 6, 2012
   North Carolina Utilities Commission, Docket No. ES-160, Sub 0
   In the Matter of Application by Town of Smithfield for Approval of an "Agreement Between
   Electric Suppliers" with Carolina Power & Light Company,
   on behalf of Town of Smithfield, NC

5. Rebuttal Testimony Dated July 29, 2010
   North Carolina Utilities Commission, Docket No. E-48, Sub 6
   In the Matter of North Carolina Eastern Municipal Power Agency 2008 Renewable Energy
   Portfolio Standards Report,
   on behalf of North Carolina Eastern Municipal Power Agency

6. Direct Testimony Dated June 3, 2010
   North Carolina Utilities Commission, Docket No. E-48, Sub 6
   In the Matter of North Carolina Eastern Municipal Power Agency 2008 Renewable Energy
   Portfolio Standards Compliance Report,
   on behalf of North Carolina Eastern Municipal Power Agency

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-2

DEP Response to FPWC Data Request No. 1-17

Duke Energy Progress
Response to
Fayetteville Public Works Commission Data Request
Data Request No. 1

Docket No. E-2, Sub 1219

Date of Request: December 16, 2019
Date of Response: January 3, 2020

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to FPWC Data Request No. 1-17, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to FPWC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

FPWC
Data Request No. 1
DEP Docket No. E-2, Sub 1219
Item No. 1-17
Page 1 of 1

Request:

Please provide a copy of all documents comparing DEP's most recently approved depreciation study and the 2018 Depreciation Study of the following for each functional plant account, and provide a detailed explanation for any material differences: (a) service life; (b) net salvage percentage; and (c) total decommissioning costs for non-nuclear production plants.

Response:

The attached schedule, FPWC-1-17 Attachment.xlsx, sets forth the comparison of DEP's most recently approved depreciation study to the 2018 Depreciation Study. The schedule sets forth average service life, survivor curve, net salvage percentage and life span date. The decommissioning study utilized is the same in both cases and has been provided in FPWC-1-18.

FPWC-1-17
Attachment.xlsx

I/A

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	2018 STUDY PROBABLE RETIREMENT DATE	2018 STUDY SURVIVOR CURVE	2018 STUDY NET SALVAGE PERCENT	2018 STUDY CALCULATED ANNUAL ACCRUAL AMOUNT	2018 STUDY CALCULATED ANNUAL ACCRUAL RATE	2016 STUDY (SETTLEMENT) PROBABLE RETIREMENT DATE	2016 STUDY (SETTLEMENT) SURVIVOR CURVE	2016 STUDY (SETTLEMENT) NET SALVAGE PERCENT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL AMOUNT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL INCREASE/(DECREASE)	REASON
	(1)	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(10)	(11)	(12)=(2)*(9)	(13)	(14)=(6)-(12)	(15)
	STEAM PRODUCTION PLANT													
311.00	STRUCTURES AND IMPROVEMENTS													
	ASHEVILLE UNIT 1	42,616,358.21	12-2027	100-R2.5 *	(4)	573,609	1.35	12-2027	100-R2.5 *	(4)	404,855	0.95	168,754	
	ASHEVILLE UNIT 2	42,579,071.25	12-2027	100-R2.5 *	(4)	1,473,445	3.46	12-2027	100-R2.5 *	(4)	1,332,725	3.13	140,720	
	MAYO UNIT 1	170,239,859.39	06-2029	100-R2.5 *	(4)	4,879,145	2.87	06-2035	100-R2.5 *	(6)	3,319,677	1.95	1,559,468	
	ROXBORO UNIT 1	17,139,904.05	06-2028	100-R2.5 *	(5)	408,845	2.39	06-2028	100-R2.5 *	(6)	431,926	2.52	(23,081)	
	ROXBORO UNIT 2	5,512,432.01	06-2028	100-R2.5 *	(5)	196,628	3.57	06-2028	100-R2.5 *	(6)	188,525	3.42	8,103	
	ROXBORO UNIT 3	37,367,402.39	06-2029	100-R2.5 *	(5)	372,911	1.00	06-2033	100-R2.5 *	(6)	325,096	0.87	47,815	
	ROXBORO UNIT 4	19,539,071.49	06-2029	100-R2.5 *	(5)	1,048,303	5.37	06-2033	100-R2.5 *	(6)	703,407	3.60	344,896	
	ROXBORO COMMON	193,990,592.95	06-2029	100-R2.5 *	(5)	14,718,151	7.59	06-2033	100-R2.5 *	(6)	9,757,727	5.03	4,960,424	
	TOTAL STRUCTURES AND IMPROVEMENTS	528,984,691.74				23,671,037	4.47				16,463,938	3.11	7,207,099	
312.00	BOILER PLANT EQUIPMENT													
	ASHEVILLE UNIT 1	149,655,719.36	12-2027	60-R1 *	(4)	7,121,696	4.76	12-2027	60-R1 *	(4)	6,270,575	4.19	851,121	
	ASHEVILLE UNIT 2	145,625,344.87	12-2027	60-R1 *	(4)	4,682,918	3.22	12-2027	60-R1 *	(4)	4,281,385	2.94	401,533	
	MAYO UNIT 1	832,479,002.87	06-2029	60-R1 *	(4)	50,461,597	6.06	06-2035	60-R1 *	(6)	33,465,656	4.02	16,995,941	
	ROXBORO UNIT 1	212,902,505.83	06-2028	60-R1 *	(5)	14,793,592	6.95	06-2028	60-R1 *	(6)	13,966,404	6.56	827,188	
	ROXBORO UNIT 2	309,506,429.33	06-2028	60-R1 *	(5)	17,017,838	5.50	06-2028	60-R1 *	(6)	15,599,124	5.04	1,418,714	
	ROXBORO UNIT 3	333,830,832.31	06-2029	60-R1 *	(5)	22,920,294	6.87	06-2033	60-R1 *	(6)	15,823,581	4.74	7,096,713	
	ROXBORO UNIT 4	404,141,708.49	06-2029	60-R1 *	(5)	14,572,511	3.61	06-2033	60-R1 *	(6)	5,375,085	1.33	9,197,426	
	ROXBORO COMMON	320,174,907.77	06-2029	60-R1 *	(5)	16,435,758	5.13	06-2033	60-R1 *	(6)	6,115,341	1.91	10,320,417	
	TOTAL BOILER PLANT EQUIPMENT	2,708,316,450.83				148,006,204	5.46				100,897,151	3.73	47,109,053	
312.10	BOILER PLANT EQUIPMENT - SCR CATALYST													
	ASHEVILLE UNIT 1	3,957,262.78	12-2027	10-S1 *	0	0	-	12-2027	10-S2 *	0	176,890	4.47	(176,890)	
	ASHEVILLE UNIT 2	1,798,265.75	12-2027	10-S1 *	0	0	-	12-2027	10-S2 *	0	97,826	5.44	(97,826)	
	MAYO UNIT 1	7,428,602.62	06-2029	10-S1 *	0	0	-	06-2035	10-S2 *	0	407,830	5.49	(407,830)	
	ROXBORO UNIT 1	7,925,144.00	06-2028	10-S1 *	0	0	-	06-2028	10-S2 *	0	145,823	1.84	(145,823)	
	ROXBORO UNIT 2	5,857,261.54	06-2028	10-S1 *	0	0	-	06-2028	10-S2 *	0	229,019	3.91	(229,019)	
	ROXBORO UNIT 3	6,541,925.15	06-2029	10-S1 *	0	245,298	3.75	06-2033	10-S2 *	0	518,120	7.92	(272,822)	
	ROXBORO UNIT 4	7,261,916.42	06-2029	10-S1 *	0	0	-	06-2033	10-S2 *	0	88,595	1.22	(88,595)	
	TOTAL BOILER PLANT EQUIPMENT - SCR CATALYST	40,770,378.26				245,298	0.60				1,664,103	4.08	(1,418,805)	
314.00	TURBOGENERATOR UNITS													
	ASHEVILLE UNIT 1	18,830,227.72	12-2027	60-S0 *	(4)	1,378,245	7.32	12-2027	60-S0 *	(4)	1,252,210	6.65	126,035	
	ASHEVILLE UNIT 2	13,968,640.50	12-2027	60-S0 *	(4)	155,826	1.12	12-2027	60-S0 *	(4)	156,449	1.12	(623)	
	MAYO UNIT 1	109,608,959.00	06-2029	60-S0 *	(4)	4,863,907	4.44	06-2035	60-S0 *	(6)	3,332,112	3.04	1,531,795	
	ROXBORO UNIT 1	45,628,567.76	06-2028	60-S0 *	(5)	3,153,178	6.91	06-2028	60-S0 *	(6)	3,038,863	6.66	114,315	
	ROXBORO UNIT 2	44,959,643.18	06-2028	60-S0 *	(5)	3,418,913	7.60	06-2028	60-S0 *	(6)	3,192,135	7.10	226,778	
	ROXBORO UNIT 3	73,030,422.44	06-2029	60-S0 *	(5)	4,601,862	6.30	06-2033	60-S0 *	(6)	3,206,036	4.39	1,395,826	
	ROXBORO UNIT 4	69,565,691.07	06-2029	60-S0 *	(5)	3,723,176	5.35	06-2033	60-S0 *	(6)	2,267,842	3.26	1,455,334	
	ROXBORO COMMON	458,890.76	06-2029	60-S0 *	(5)	14,425	3.14	06-2033	60-S0 *	(6)	10,830	2.36	3,595	
	TOTAL TURBOGENERATOR UNITS	376,051,042.43				21,309,532	5.67				16,456,477	4.38	4,853,055	
315.00	ACCESSORY ELECTRIC EQUIPMENT													
	ASHEVILLE UNIT 1	17,304,563.70	12-2027	70-R1 *	(4)	896,804	5.18	12-2027	65-R1.5 *	(4)	821,967	4.75	74,837	
	ASHEVILLE UNIT 2	10,774,312.04	12-2027	70-R1 *	(4)	0	-	12-2027	65-R1.5 *	(4)	0	0.00	0	
	MAYO UNIT 1	66,829,604.18	06-2029	70-R1 *	(4)	3,607,025	5.40	06-2035	65-R1.5 *	(6)	2,372,451	3.55	1,234,574	
	ROXBORO UNIT 1	27,911,638.64	06-2028	70-R1 *	(5)	2,151,100	7.71	06-2028	65-R1.5 *	(6)	2,065,461	7.40	85,639	
	ROXBORO UNIT 2	24,223,049.38	06-2028	70-R1 *	(5)	883,710	3.65	06-2028	65-R1.5 *	(6)	859,918	3.55	23,792	
	ROXBORO UNIT 3	42,579,385.55	06-2029	70-R1 *	(5)	2,913,552	6.84	06-2033	65-R1.5 *	(6)	1,962,910	4.61	950,642	
	ROXBORO UNIT 4	43,547,824.88	06-2029	70-R1 *	(5)	2,486,371	5.71	06-2033	65-R1.5 *	(6)	1,328,209	3.05	1,158,162	
	ROXBORO COMMON	23,722,266.18	06-2029	70-R1 *	(5)	1,723,633	7.27	06-2033	65-R1.5 *	(6)	1,188,486	5.01	535,147	
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	256,892,644.55				14,662,195	5.71				10,599,402	4.13	4,062,793	
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT													
	ASHEVILLE UNIT 1	10,334,480.63	12-2027	45-S0 *	(4)	695,241	6.73	12-2027	50-S0 *	(4)	666,574	6.45	28,667	
	ASHEVILLE UNIT 2	5,120,201.92	12-2027	45-S0 *	(4)	91,397	1.79	12-2027	50-S0 *	(4)	89,092	1.74	2,305	
	MAYO UNIT 1	13,338,741.21	06-2029	45-S0 *	(4)	840,910	6.30	06-2035	50-S0 *	(6)	518,877	3.89	322,033	
	ROXBORO UNIT 1	4,072,524.77	06-2028	45-S0 *	(5)	281,244	6.91	06-2028	50-S0 *	(6)	252,089	6.19	29,155	
	ROXBORO UNIT 2	4,425,440.03	06-2028	45-S0 *	(5)	214,299	4.84	06-2028	50-S0 *	(6)	170,379	3.85	43,920	
	ROXBORO UNIT 3	4,581,632.45	06-2029	45-S0 *	(5)	270,285	5.90	06-2033	50-S0 *	(6)	191,512	4.18	78,773	
	ROXBORO UNIT 4	5,430,383.41	06-2029	45-S0 *	(5)	308,691	5.68	06-2033	50-S0 *	(6)	207,984	3.83	100,707	
	ROXBORO COMMON	20,631,298.87	06-2029	45-S0 *	(5)	1,574,562	7.63	06-2033	50-S0 *	(6)	1,126,469	5.46	448,093	
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT	67,934,703.29				4,276,629	6.30				3,222,976	4.74	1,053,653	
	TOTAL STEAM PRODUCTION PLANT	**3,978,949,911.10**				**212,170,895**	**5.33**				**149,304,047**	**3.75**	**62,866,848**	**Shorter life span dates for Mayo 1, Roxboro 3 and 4**

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	2018 STUDY PROBABLE RETIREMENT DATE	2018 STUDY SURVIVOR CURVE	2018 STUDY NET SALVAGE PERCENT	2018 STUDY CALCULATED ANNUAL ACCRUAL AMOUNT	2018 STUDY CALCULATED ANNUAL ACCRUAL RATE	2016 STUDY (SETTLEMENT) PROBABLE RETIREMENT DATE	2016 STUDY (SETTLEMENT) SURVIVOR CURVE	2016 STUDY (SETTLEMENT) NET SALVAGE PERCENT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL AMOUNT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL INCREASE/(DECREASE)	REASON
	(1)	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(10)	(11)	(12)=(2)*(9)	(13)	(14)=(6)-(12)	(15)
	NUCLEAR PRODUCTION PLANT													
321.00	STRUCTURES AND IMPROVEMENTS													
	BRUNSWICK UNIT 1	423,009,418.66	09-2036	75-S1 *	(1)	14,175,485	3.35	09-2036	80-S1 *	(2)	11,082,847	2.62	3,092,638	
	BRUNSWICK UNIT 2	397,968,469.79	12-2034	75-S1 *	(1)	11,520,013	2.89	12-2034	80-S1 *	(2)	10,506,368	2.64	1,013,645	
	HARRIS UNIT 1	1,996,266,873.69	10-2046	75-S1 *	(2)	32,248,496	1.62	10-2046	80-S1 *	(3)	32,738,777	1.64	(490,281)	
	HARRIS DISALLOWANCE	(105,862,561.00)	10-2046			(1,369,567)	1.29	10-2046			(1,365,503)	1.29	(4,064)	
	ROBINSON UNIT 2	373,649,660.90	07-2030	75-S1 *	(1)	16,338,445	4.37	07-2030	80-S1 *	(1)	12,704,088	3.40	3,634,357	
	TOTAL STRUCTURES AND IMPROVEMENTS	3,085,031,862.04				72,912,872	2.36				65,666,577	2.13	7,246,295	
322.00	REACTOR PLANT EQUIPMENT													
	BRUNSWICK UNIT 1	612,117,283.68	09-2036	52-R2 *	(1)	19,312,794	3.16	09-2036	55-R1.5 *	(2)	17,139,284	2.80	2,173,510	
	BRUNSWICK UNIT 2	544,476,825.16	12-2034	52-R2 *	(1)	17,115,022	3.14	12-2034	55-R1.5 *	(2)	15,626,485	2.87	1,488,537	
	HARRIS UNIT 1	1,075,559,612.15	10-2046	52-R2 *	(2)	28,850,918	2.68	10-2046	55-R1.5 *	(3)	29,362,777	2.73	(511,859)	
	HARRIS DISALLOWANCE	(132,409,445.00)	10-2046			(1,713,010)	1.29	10-2046			(1,707,926)	1.29	(5,084)	
	ROBINSON UNIT 2	462,756,240.49	07-2030	52-R2 *	(1)	19,464,027	4.21	07-2030	55-R1.5 *	(1)	15,733,712	3.40	3,730,315	
	TOTAL REACTOR PLANT EQUIPMENT	2,562,500,516.48				83,029,751	3.24				76,154,332	2.97	6,875,419	
323.00	TURBOGENERATOR UNITS													
	BRUNSWICK UNIT 1	285,997,062.33	09-2036	40-S0 *	(1)	11,823,008	4.13	09-2036	50-S0 *	(2)	8,751,510	3.06	3,071,498	
	BRUNSWICK UNIT 2	172,548,284.27	12-2034	40-S0 *	(1)	6,442,418	3.73	12-2034	50-S0 *	(2)	5,728,603	3.32	713,815	
	HARRIS UNIT 1	535,687,360.49	10-2046	40-S0 *	(2)	17,371,808	3.24	10-2046	50-S0 *	(3)	13,285,047	2.48	4,086,761	
	HARRIS DISALLOWANCE	(610,466.00)	10-2046			(7,898)	1.29	10-2046			(7,874)	1.29	(24)	
	ROBINSON UNIT 2	333,276,803.83	07-2030	40-S0 *	(1)	26,899,155	8.07	07-2030	50-S0 *	(1)	16,797,151	5.04	10,102,004	
	TOTAL TURBOGENERATOR UNITS	1,326,899,044.92				62,528,491	4.71				44,554,437	3.36	17,974,054	
324.00	ACCESSORY ELECTRIC EQUIPMENT													
	BRUNSWICK UNIT 1	161,647,774.74	09-2036	50-R2.5 *	(1)	6,821,086	4.22	09-2036	55-R2.5 *	(2)	6,094,121	3.77	726,965	
	BRUNSWICK UNIT 2	210,342,927.28	12-2034	50-R2.5 *	(1)	8,431,189	4.01	12-2034	55-R2.5 *	(2)	6,730,974	3.20	1,700,215	
	HARRIS UNIT 1	820,436,969.84	10-2046	50-R2.5 *	(2)	16,303,928	1.99	10-2046	55-R2.5 *	(3)	15,260,128	1.86	1,043,800	
	HARRIS DISALLOWANCE	(256,837,664.66)	10-2046			(3,322,766)	1.29	10-2046			(3,312,904)	1.29	(9,862)	
	ROBINSON UNIT 2	279,070,966.07	07-2030	50-R2.5 *	(1)	17,942,656	6.43	07-2030	55-R2.5 *	(1)	10,716,325	3.84	7,226,331	
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	1,214,660,973.27				46,176,093	3.80				35,488,644	2.92	10,687,449	
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT													
	BRUNSWICK UNIT 1	201,192,590.16	09-2036	50-R1.5 *	(1)	7,865,762	3.91	09-2036	50-R1 *	(2)	7,162,456	3.56	703,306	
	BRUNSWICK UNIT 2	68,906,220.33	12-2034	50-R1.5 *	(1)	2,534,043	3.68	12-2034	50-R1 *	(2)	2,425,499	3.52	108,544	
	HARRIS UNIT 1	247,301,101.58	10-2046	50-R1.5 *	(2)	5,889,127	2.38	10-2046	50-R1 *	(3)	5,836,306	2.36	52,821	
	HARRIS DISALLOWANCE	(55,577,154.00)	10-2046			(719,014)	1.29	10-2046			(716,880)	1.29	(2,134)	
	ROBINSON UNIT 2	190,043,010.80	07-2030	50-R1.5 *	(1)	12,040,133	6.34	07-2030	50-R1 *	(1)	10,661,413	5.61	1,378,720	
	TOTAL MISCELLANEOUS PLANT EQUIPMENT	651,865,768.87				27,610,051	4.24				25,368,794	3.89	2,241,257	
	TOTAL NUCLEAR PRODUCTION PLANT	**8,840,958,165.58**				**292,257,258**	**3.31**				**247,232,784**	**2.80**	**45,024,474**	**Shorter interim survivor curve**
	HYDRAULIC PRODUCTION PLANT													
331.00	STRUCTURES AND IMPROVEMENTS													
	BLEWETT	6,620,300.84	06-2055	110-R2 *	(33)	187,401	2.83	06-2055	110-R2 *	(41)	171,466	2.59	15,935	
	MARSHALL	1,523,286.57	06-2035	110-R2 *	(16)	107,146	7.03	06-2035	110-R2 *	(16)	103,127	6.77	4,019	
	TILLERY	6,634,057.32	06-2055	110-R2 *	(29)	202,328	3.05	06-2055	110-R2 *	(33)	157,227	2.37	45,101	
	WALTERS	3,472,324.03	06-2034	110-R2 *	(6)	112,577	3.24	06-2034	110-R2 *	(6)	109,378	3.15	3,199	
	TOTAL STRUCTURES AND IMPROVEMENTS	18,249,968.76				609,452	3.34				541,198	2.97	68,254	
332.00	RESERVOIRS, DAMS AND WATERWAYS													
	BLEWETT	8,275,323.29	06-2055	120-R3 *	(33)	160,135	1.94	06-2055	120-R3 *	(41)	183,712	2.22	(23,577)	
	MARSHALL	4,071,208.19	06-2035	120-R3 *	(16)	143,440	3.52	06-2035	120-R3 *	(16)	134,350	3.30	9,090	
	TILLERY	6,796,645.31	06-2055	120-R3 *	(29)	110,074	1.62	06-2055	120-R3 *	(33)	123,699	1.82	(13,625)	
	WALTERS	34,543,362.20	06-2034	120-R3 *	(6)	1,195,944	3.46	06-2034	120-R3 *	(6)	991,394	2.87	204,550	
	TOTAL RESERVOIRS, DAMS AND WATERWAYS	53,686,538.99				1,609,593	3.00				1,433,155	2.67	176,438	

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DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	2018 STUDY PROBABLE RETIREMENT DATE	2018 STUDY SURVIVOR CURVE	2018 STUDY NET SALVAGE PERCENT	2018 STUDY CALCULATED ANNUAL ACCRUAL AMOUNT	2018 STUDY CALCULATED ANNUAL ACCRUAL RATE	2016 STUDY (SETTLEMENT) PROBABLE RETIREMENT DATE	2016 STUDY (SETTLEMENT) SURVIVOR CURVE	2016 STUDY (SETTLEMENT) NET SALVAGE PERCENT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL AMOUNT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL INCREASE/(DECREASE)	REASON
	(1)	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(10)	(11)	(12)=(2)*(9)	(13)	(14)=(6)-(12)	(15)
333.00	WATER WHEELS, TURBINES AND GENERATORS													
	BLEWETT	13,436,525.48	06-2055	75-R1.5 *	(33)	536,807	4.00	06-2055	70-R1.5 *	(41)	650,328	4.84	(113,521)	
	MARSHALL	6,041,207.23	06-2035	75-R1.5 *	(16)	189,470	3.14	06-2035	70-R1.5 *	(16)	180,028	2.98	9,442	
	TILLERY	14,142,264.87	06-2055	75-R1.5 *	(29)	530,595	3.75	06-2055	70-R1.5 *	(33)	545,891	3.86	(15,296)	
	WALTERS	4,456,120.96	06-2034	75-R1.5 *	(6)	155,664	3.49	06-2034	70-R1.5 *	(6)	139,922	3.14	15,742	
	TOTAL WATER WHEELS, TURBINES AND GENERATORS	38,076,118.54				1,412,536	3.71				1,516,169	3.98	(103,633)	
334.00	ACCESSORY ELECTRIC EQUIPMENT													
	BLEWETT	7,543,722.48	06-2055	55-R1 *	(33)	338,949	4.49	06-2055	60-S1 *	(41)	287,416	3.81	51,533	
	MARSHALL	1,179,515.99	06-2035	55-R1 *	(16)	40,208	3.41	06-2035	60-S1 *	(16)	40,575	3.44	(367)	
	TILLERY	3,853,242.31	06-2055	55-R1 *	(29)	137,612	3.57	06-2055	60-S1 *	(33)	131,010	3.40	6,602	
	WALTERS	13,242,973.33	06-2034	55-R1 *	(6)	856,757	6.47	06-2034	60-S1 *	(6)	744,255	5.62	112,502	
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	25,819,454.11				1,373,526	5.32				1,203,256	4.66	170,270	
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT													
	BLEWETT	1,826,329.58	06-2055	55-S0 *	(33)	66,903	3.66	06-2055	55-S0.5 *	(41)	68,853	3.77	(1,950)	
	MARSHALL	200,696.66	06-2035	55-S0 *	(16)	10,921	5.44	06-2035	55-S0.5 *	(16)	10,496	5.23	425	
	TILLERY	1,227,560.24	06-2055	55-S0 *	(29)	32,943	2.68	06-2055	55-S0.5 *	(33)	33,144	2.70	(201)	
	WALTERS	1,756,787.00	06-2034	55-S0 *	(6)	96,765	5.51	06-2034	55-S0.5 *	(6)	84,853	4.83	11,912	
	TOTAL MISCELLANEOUS PLANT EQUIPMENT	5,011,373.48				207,532	4.14				197,346	3.94	10,186	
336.00	ROADS, RAILROADS, AND BRIDGES													
	MARSHALL	12,946.58	06-2035	75-R3 *	(16)	364	2.81	06-2035	75-R3 *	(16)	368	2.84	(4)	
	WALTERS	8,258.48	06-2034	75-R3 *	(6)	24	0.29	06-2034	75-R3 *	(6)	43	0.52	(19)	
	TOTAL ROADS, RAILROADS, AND BRIDGES	21,205.06				388	1.83				411	1.94	(23)	
	TOTAL HYDRAULIC PRODUCTION PLANT	**140,864,658.94**				**5,213,027**	**3.70**				**4,891,535**	**3.47**	**321,492**	
	OTHER PRODUCTION PLANT													
341.00	STRUCTURES AND IMPROVEMENTS													
	ASHEVILLE IC TURBINE	31,762,836.46	06-2039	50-S1 *	(3)	975,677	3.07	06-2039	50-S2 *	(3)	937,004	2.95	38,673	
	BLEWETT IC TURBINES	979,562.66	06-2024	50-S1 *	(7)	11,136	1.14	06-2024	50-S2 *	(7)	13,322	1.36	(2,186)	
	DARLINGTON IC TURBINE UNITS 1-11	362,282.66	06-2020	50-S1 *	(7)	0	-	06-2020	50-S2 *	(6)	0	-	0	
	DARLINGTON IC TURBINE UNITS 12 AND 13	8,403,245.66	06-2037	50-S1 *	(7)	69,646	0.83	06-2037	50-S2 *	(6)	12,605	0.15	57,041	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	9,013,914.23	06-2040	50-S1 *	(4)	254,463	2.82	06-2040	50-S2 *	(4)	239,770	2.66	14,693	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	1,356,819.84	06-2049	50-S1 *	(4)	40,347	2.97	06-2049	50-S2 *	(4)	37,177	2.74	3,170	
	SMITH IC TURBINES (RICHMOND COUNTY)	19,344,678.47	06-2041	50-S1 *	(2)	579,000	2.99	06-2041	50-S2 *	(2)	559,061	2.89	19,939	
	SUTTON BLACKSTART	11,574,792.86	06-2057	50-S1 *	(9)	231,353	2.00	06-2017	50-S2 *	(20)	0	0.00	231,353	
	WEATHERSPOON IC TURBINES	3,568,977.41	06-2024	50-S1 *	(21)	92,356	2.59	06-2024	50-S2 *	(20)	53,892	1.51	38,464	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	47,694,242.52	06-2042	50-S1 *	(4)	440,153	0.92	06-2042	50-S2 *	(3)	429,248	0.90	10,905	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	40,103,160.35	06-2051	50-S1 *	(8)	1,232,177	3.07	06-2051	50-S2 *	(7)	1,158,981	2.89	73,196	
	SUTTON COMBINED CYCLE	13,462,878.60	06-2053	50-S1 *	(3)	512,673	3.81	06-2053	50-S2 *	(2)	476,586	3.54	36,087	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	25,476,302.18	06-2052	50-S1 *	(6)	711,705	2.79	06-2052	50-S2 *	(5)	606,336	2.38	105,369	
	TOTAL STRUCTURES AND IMPROVEMENTS	213,103,693.90				5,150,686	2.42				4,523,982	2.12	626,704	
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR													
	CAMP LEJUNE	26,130.74	06-2040	30-S2.5 *	(9)	1,307	5.00	06-2040	30-S2.5 *	(9)	1,307	5.00	0	
	FAYETTEVILLE	3,957.51	06-2040	30-S2.5 *	(11)	204	5.15	06-2040	30-S2.5 *	(11)	204	5.15	0	
	ELM CITY	3,925.80	06-2041	30-S2.5 *	(15)	203	5.17	06-2041	30-S2.5 *	(15)	203	5.17	0	
	TOTAL STRUCTURES AND IMPROVEMENTS - SOLAR	34,014.05				1,714	5.04				1,714	5.04	0	
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES													
	ASHEVILLE IC TURBINE	5,115,723.34	06-2039	45-R2 *	(3)	148,602	2.90	06-2039	50-R2.5 *	(3)	115,104	2.25	33,498	
	BLEWETT IC TURBINES	413,479.62	06-2024	45-R2 *	(7)	7,229	1.75	06-2024	50-R2.5 *	(7)	7,691	1.86	(462)	
	DARLINGTON IC TURBINE UNITS 1-11	5,048,367.44	06-2020	45-R2 *	(7)	0	-	06-2020	50-R2.5 *	(6)	0	-	0	
	DARLINGTON IC TURBINE UNITS 12 AND 13	7,243,963.20	06-2037	45-R2 *	(7)	108,699	1.50	06-2037	50-R2.5 *	(6)	95,620	1.32	13,079	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	7,363,988.43	06-2040	45-R2 *	(4)	219,470	2.98	06-2040	50-R2.5 *	(4)	203,982	2.77	15,488	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	1,461,178.80	06-2049	45-R2 *	(4)	43,476	2.98	06-2049	50-R0.5 *	(4)	43,689	2.99	(213)	
	SMITH IC TURBINES (RICHMOND COUNTY)	8,473,790.16	06-2041	45-R2 *	(2)	267,152	3.15	06-2041	50-R2.5 *	(2)	255,061	3.01	12,091	
	SUTTON BLACKSTART	5,990,884.76	06-2057	45-R2 *	(9)	188,103	3.14	06-2017	50-R2.5 *	(20)	0	0.00	188,103	
	WEATHERSPOON IC TURBINES	1,651,095.21	06-2024	45-R2 *	(21)	140,115	8.49	06-2024	50-R2.5 *	(20)	87,508	5.30	52,607	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	13,523,522.65	06-2042	45-R2 *	(4)	405,772	3.00	06-2042	50-R2.5 *	(3)	370,545	2.74	35,227	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	22,575,250.21	06-2051	45-R2 *	(8)	702,612	3.11	06-2051	50-R2.5 *	(7)	659,197	2.92	43,415	
	SUTTON COMBINED CYCLE	19,656,537.55	06-2053	45-R2 *	(3)	835,790	4.25	06-2053	50-R2.5 *	(2)	575,937	2.93	259,853	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	25,423,310.37	06-2052	45-R2 *	(6)	845,788	3.33	06-2052	50-R2.5 *	(5)	780,496	3.07	65,292	
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES	123,941,091.74				3,912,808	3.16				3,194,830	2.58	717,978	

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

	ACCOUNT (1)	ORIGINAL COST AS OF DECEMBER 31, 2018 (2)	2018 STUDY PROBABLE RETIREMENT DATE (3)	2018 STUDY SURVIVOR CURVE (4)	2018 STUDY NET SALVAGE PERCENT (5)	2018 STUDY CALCULATED ANNUAL ACCRUAL AMOUNT (6)	2018 STUDY CALCULATED ANNUAL ACCRUAL RATE (8)	2016 STUDY (SETTLEMENT) PROBABLE RETIREMENT DATE (9)	2016 STUDY (SETTLEMENT) SURVIVOR CURVE (10)	2016 STUDY (SETTLEMENT) NET SALVAGE PERCENT (11)	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL AMOUNT (12)=(2)*(9)	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL RATE (13)	ANNUAL ACCRUAL INCREASE/(DECREASE) (14)=(6)-(12)	REASON (15)
343.00	PRIME MOVERS													
	ASHEVILLE IC TURBINE	51,871,873.24	06-2039	30-R0.5 *	(3)	2,634,563	5.08	06-2039	35-S0 *	(3)	1,649,526	3.18	985,037	
	BLEWETT IC TURBINES	8,455,727.27	06-2024	30-R0.5 *	(7)	336,664	3.98	06-2024	35-S0 *	(7)	317,935	3.76	18,729	
	DARLINGTON IC TURBINE UNITS 1-11	22,476,731.53	06-2020	30-R0.5 *	(7)	9,767,204	43.45	06-2020	35-S0 *	(6)	4,432,411	19.72	5,334,793	
	DARLINGTON IC TURBINE UNITS 12 AND 13	39,502,461.61	06-2037	30-R0.5 *	(7)	2,901,267	7.34	06-2037	35-S0 *	(6)	2,101,531	5.32	799,736	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	121,712,253.32	06-2040	30-R0.5 *	(4)	4,737,903	3.89	06-2040	35-S0 *	(4)	4,649,408	3.82	88,495	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	61,526,436.54	06-2049	30-R0.5 *	(4)	2,326,209	3.78	06-2049	35-S0 *	(4)	2,128,815	3.46	197,394	
	SMITH IC TURBINES (RICHMOND COUNTY)	230,437,633.01	06-2041	30-R0.5 *	(2)	14,883,340	6.46	06-2041	35-S0 *	(2)	12,581,895	5.46	2,301,445	
	SUTTON BLACKSTART	65,019,558.96	06-2057	30-R0.5 *	(9)	2,651,182	4.08	06-2017	35-S0 *	(20)	0	0.00	2,651,182	
	WEATHERSPOON IC TURBINES	12,638,464.88	06-2024	30-R0.5 *	(21)	86,525	0.68	06-2024	35-S0 *	(20)	24,013	0.19	62,512	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	114,272,116.59	06-2042	30-R0.5 *	(4)	8,046,676	7.04	06-2042	35-S0 *	(3)	6,536,365	5.72	1,510,311	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	236,173,460.30	06-2051	30-R0.5 *	(8)	9,344,070	3.96	06-2051	35-S0 *	(7)	9,069,061	3.84	275,009	
	SUTTON COMBINED CYCLE	361,361,292.77	06-2053	30-R0.5 *	(3)	15,105,488	4.18	06-2053	35-S0 *	(2)	12,864,462	3.56	2,241,026	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	443,686,010.74	06-2052	30-R0.5 *	(6)	19,052,498	4.29	06-2052	35-S0 *	(5)	17,569,966	3.96	1,482,532	
	TOTAL PRIME MOVERS	1,769,134,020.76				91,873,589	5.19				73,925,388	4.18	17,948,201	
343.10	PRIME MOVERS - ROTABLE PARTS													
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	39,318,264.60	06-2042	6-L0.5 *	40	4,840,705	12.31	06-2042	5-L0.5 *	40	5,304,034	13.49	(463,329)	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	44,987,832.65	06-2051	6-L0.5 *	40	5,974,679	13.28	06-2051	5-L0.5 *	40	6,824,654	15.17	(849,975)	
	SUTTON COMBINED CYCLE	29,483,115.01	06-2053	6-L0.5 *	40	3,577,906	12.14	06-2053	5-L0.5 *	40	4,328,121	14.68	(750,215)	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	56,542,095.59	06-2052	6-L0.5 *	40	7,057,740	12.48	06-2052	5-L0.5 *	40	8,300,380	14.68	(1,242,640)	
	TOTAL PRIME MOVERS - ROTABLE PARTS	170,331,307.85				21,451,030	12.59				24,757,189	14.53	(3,306,159)	
344.00	GENERATORS													
	ASHEVILLE IC TURBINE	7,769,953.49	06-2039	50-R2 *	(3)	233,653	3.01	06-2039	55-R2 *	(3)	219,890	2.83	13,763	
	BLEWETT IC TURBINES	1,988,284.95	06-2024	50-R2 *	(7)	0	-	06-2024	55-R2 *	(7)	0	-	0	
	DARLINGTON IC TURBINE UNITS 1-11	12,472,614.73	06-2020	50-R2 *	(7)	3,097,560	24.83	06-2020	55-R2 *	(6)	1,405,664	11.27	1,691,896	
	DARLINGTON IC TURBINE UNITS 12 AND 13	17,131,838.45	06-2037	50-R2 *	(7)	735,468	4.29	06-2037	55-R2 *	(6)	671,568	3.92	63,900	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	22,068,501.33	06-2040	50-R2 *	(4)	632,402	2.87	06-2040	55-R2 *	(4)	639,987	2.90	(7,585)	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	13,021,303.33	06-2049	50-R2 *	(4)	390,823	3.00	06-2049	55-R2 *	(4)	371,107	2.85	19,716	
	SMITH IC TURBINES (RICHMOND COUNTY)	37,046,160.65	06-2041	50-R2 *	(2)	3,735,595	10.08	06-2041	55-R2 *	(2)	2,011,607	5.43	1,723,988	
	SUTTON BLACKSTART	2,145,710.72	06-2057	50-R2 *	(9)	59,357	2.77	06-2017	55-R2 *	(20)	0	0.00	59,357	
	WEATHERSPOON IC TURBINES	2,095,743.68	06-2024	50-R2 *	(21)	0	-	06-2024	55-R2 *	(20)	0	-	0	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	40,449,074.75	06-2042	50-R2 *	(4)	0	-	06-2042	55-R2 *	(3)	432,805	1.07	(432,805)	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	31,516,637.44	06-2051	50-R2 *	(8)	946,600	3.00	06-2051	55-R2 *	(7)	913,982	2.90	32,618	
	SUTTON COMBINED CYCLE	44,450,493.34	06-2053	50-R2 *	(3)	1,335,598	3.00	06-2053	55-R2 *	(2)	1,280,174	2.88	55,424	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	55,122,184.33	06-2052	50-R2 *	(6)	1,748,825	3.17	06-2052	55-R2 *	(5)	1,692,251	3.07	56,574	
	TOTAL GENERATORS	287,278,501.19				12,915,881	4.50				9,639,035	3.36	3,276,846	
344.20	GENERATORS - SOLAR													
	CAMP LEJUNE	15,956,191.94	06-2040	25-S2.5 *	(9)	822,344	5.15	06-2040	25-S2.5 *	(8)	802,596	5.03	19,748	
	FAYETTEVILLE	32,469,234.56	06-2040	25-S2.5 *	(11)	1,708,709	5.26	06-2040	25-S2.5 *	(10)	1,662,425	5.12	46,284	
	ELM CITY	51,863,631.58	06-2041	25-S2.5 *	(15)	2,731,170	5.27	06-2041	25-S2.5 *	(15)	2,681,350	5.17	49,820	
	WARSAW	87,181,902.80	06-2040	25-S2.5 *	(12)	4,629,736	5.31	06-2040	25-S2.5 *	(11)	4,516,023	5.18	113,713	
	TOTAL GENERATORS - SOLAR	187,470,960.88				9,891,959	5.28				9,662,394	5.15	229,565	
345.00	ACCESSORY ELECTRIC EQUIPMENT													
	ASHEVILLE IC TURBINE	13,502,429.56	06-2039	50-R1.5 *	(3)	549,433	4.07	06-2039	50-R1.5 *	(3)	495,539	3.67	53,894	
	BLEWETT IC TURBINES	1,418,891.29	06-2024	50-R1.5 *	(7)	12,494	0.88	06-2024	50-R1.5 *	(7)	16,743	1.18	(4,249)	
	DARLINGTON IC TURBINE UNITS 1-11	4,869,111.48	06-2020	50-R1.5 *	(7)	410,605	8.43	06-2020	50-R1.5 *	(6)	389,042	7.99	21,563	
	DARLINGTON IC TURBINE UNITS 12 AND 13	10,782,807.93	06-2037	50-R1.5 *	(7)	433,757	4.02	06-2037	50-R1.5 *	(6)	402,199	3.73	31,558	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	19,926,915.26	06-2040	50-R1.5 *	(4)	576,702	2.89	06-2040	50-R1.5 *	(4)	599,800	3.01	(23,098)	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	10,599,164.94	06-2049	50-R1.5 *	(4)	321,295	3.03	06-2049	50-R1.5 *	(4)	311,615	2.94	9,680	
	SMITH IC TURBINES (RICHMOND COUNTY)	29,257,399.18	06-2041	50-R1.5 *	(2)	894,076	3.06	06-2041	50-R1.5 *	(2)	883,573	3.02	10,503	
	SUTTON BLACKSTART	13,595,340.46	06-2057	50-R1.5 *	(9)	379,136	2.79	06-2017	50-R1.5 *	(20)	0	0.00	379,136	
	WEATHERSPOON IC TURBINES	3,003,206.27	06-2024	50-R1.5 *	(21)	329,700	10.98	06-2024	50-R1.5 *	(20)	258,876	8.62	70,824	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	21,653,205.44	06-2042	50-R1.5 *	(4)	723,937	3.34	06-2042	50-R1.5 *	(3)	688,572	3.18	35,365	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	51,327,924.43	06-2051	50-R1.5 *	(8)	1,621,061	3.16	06-2051	50-R1.5 *	(7)	1,570,634	3.06	50,427	
	SUTTON COMBINED CYCLE	62,940,670.78	06-2053	50-R1.5 *	(3)	2,012,729	3.20	06-2053	50-R1.5 *	(2)	1,982,631	3.15	30,098	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	76,581,369.69	06-2052	50-R1.5 *	(6)	2,531,320	3.31	06-2052	50-R1.5 *	(5)	2,488,895	3.25	42,425	
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	319,458,436.71				10,796,245	3.38				10,088,119	3.16	708,126	
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR													
	CAMP LEJUNE	2,761,117.30	06-2040	25-S2.5 *	(9)	141,616	5.13	06-2040	25-S2.5 *	(8)	138,332	5.01	3,284	
	FAYETTEVILLE	533,260.74	06-2040	25-S2.5 *	(11)	28,033	5.26	06-2040	25-S2.5 *	(10)	27,356	5.13	677	
	ELM CITY	133,458.18	06-2041	25-S2.5 *	(15)	6,990	5.24	06-2041	25-S2.5 *	(15)	6,900	5.17	90	
	WARSAW	1,258,878.46	06-2040	25-S2.5 *	(12)	66,731	5.30	06-2040	25-S2.5 *	(11)	65,084	5.17	1,647	
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR	4,686,714.68				243,370	5.19				237,672	5.07	5,698	

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

			2018 STUDY					2016 STUDY (SETTLEMENT)							
	ACCOUNT (1)	ORIGINAL COST AS OF DECEMBER 31, 2018 (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE (4)	NET SALVAGE PERCENT (5)	CALCULATED ANNUAL ACCRUAL AMOUNT (6)	CALCULATED ANNUAL ACCRUAL RATE (8)	PROBABLE RETIREMENT DATE (9)	SURVIVOR CURVE (10)	NET SALVAGE PERCENT (11)	CALCULATED ANNUAL ACCRUAL AMOUNT (12)=(2)*(9)	CALCULATED ANNUAL ACCRUAL RATE (13)	ANNUAL ACCRUAL INCREASE/(DECREASE) (14)=(6)-(12)	REASON (15)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT													
	ASHEVILLE IC TURBINE	3,414,473.38	06-2039	30-S1 *	(3)	165,627	4.85	06-2039	40-S1.5 *	(3)	118,141	3.46	47,486	
	BLEWETT IC TURBINES	204,914.55	06-2024	30-S1 *	(7)	26,575	12.97	06-2024	40-S1.5 *	(7)	22,172	10.82	4,403	
	DARLINGTON IC TURBINE UNITS 1-11	90,349.83	06-2020	30-S1 *	(7)	177,654	196.63	06-2020	40-S1.5 *	(6)	361	0.40	177,293	
	DARLINGTON IC TURBINE UNITS 12 AND 13	1,432,545.23	06-2037	30-S1 *	(7)	44,312	3.09	06-2037	40-S1.5 *	(6)	40,684	2.84	3,628	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	1,316,904.66	06-2040	30-S1 *	(4)	31,177	2.37	06-2040	40-S1.5 *	(4)	28,709	2.18	2,468	
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	1,125,769.23	06-2049	30-S1 *	(4)	38,046	3.38	06-2049	40-S1.5 *	(4)	29,383	2.61	8,663	
	SMITH IC TURBINES (RICHMOND COUNTY)	7,653,551.58	06-2041	30-S1 *	(2)	624,277	8.16	06-2041	40-S1.5 *	(2)	414,057	5.41	210,220	
	SUTTON BLACKSTART	1,861,416.34	06-2057	30-S1 *	(9)	73,523	3.95	06-2017	40-S1.5 *	(20)	0	0.00	73,523	
	WEATHERSPOON IC TURBINES	721,477.59	06-2024	30-S1 *	(21)	123,221	17.08	06-2024	40-S1.5 *	(20)	98,121	13.60	25,100	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	4,901,411.09	06-2042	30-S1 *	(4)	26,262	0.54	06-2042	40-S1.5 *	(3)	115,673	2.36	(89,411)	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	8,419,845.29	06-2051	30-S1 *	(8)	337,867	4.01	06-2051	40-S1.5 *	(7)	266,067	3.16	71,800	
	SUTTON COMBINED CYCLE	8,363,725.23	06-2053	30-S1 *	(3)	335,284	4.01	06-2053	40-S1.5 *	(2)	266,803	3.19	68,481	
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	11,795,130.01	06-2052	30-S1 *	(6)	489,752	4.15	06-2052	40-S1.5 *	(5)	386,880	3.28	102,872	
	TOTAL MISCELLANEOUS PLANT EQUIPMENT	51,301,514.01				2,493,577	4.86				1,787,051	3.48	706,526	
346.20	MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR													
	ELM CITY	10,069.36	06-2041	30-S2.5 *	(15)	528	5.24	06-2041	30-S2.5 *	(15)	528	5.24	0	
	WARSAW	19,111.49	06-2040	30-S2.5 *	(12)	1,017	5.32	06-2040	30-S2.5 *	(12)	1,017	5.32	0	
	TOTAL MISCELLANEOUS PLANT EQUIPMENT - SOLAR	29,180.85				1,545	5.29				1,545	5.29	0	
	TOTAL OTHER PRODUCTION PLANT	**3,126,769,436.62**				**158,732,404**	**5.08**				**137,818,919**	**4.41**	**20,913,485**	
	TOTAL PRODUCTION	**16,087,542,172.24**				**668,373,584**	**4.15**				**539,247,285**	**3.35**	**129,126,299**	**Shorter interim survivor curves and change in life span for Sutton Blac**
	TRANSMISSION PLANT													
352.00	STRUCTURES AND IMPROVEMENTS	90,193,203.79		60-R3	(10)	1,622,028	1.80		60-R3	(10)	1,605,439	1.78	16,589	
353.00	STATION EQUIPMENT	1,070,174,832.08		55-R1.5	(15)	23,628,452	2.21		60-R1	(15)	20,333,322	1.90	3,295,130	
354.00	TOWERS AND FIXTURES	78,936,364.53		75-R4	(20)	936,307	1.19		70-R4	(20)	1,065,641	1.35	(129,334)	
355.00	POLES AND FIXTURES	743,280,241.54		49-R1.5	(40)	19,031,917	2.56		48-R1.5	(30)	16,500,821	2.22	2,531,096	
356.00	OVERHEAD CONDUCTORS AND DEVICES	551,039,389.11		65-R2.5	(40)	11,383,033	2.07		70-R2	(30)	8,596,214	1.56	2,786,819	
357.00	UNDERGROUND CONDUIT	32,286.46		60-R4	0	559	1.73		60-R4	0	559	1.73	0	
358.00	UNDERGROUND CONDUCTORS AND DEVICES	21,603,999.00		45-S2.5	0	504,195	2.33		45-S2.5	0	496,892	2.30	7,303	
359.00	ROADS AND TRAILS	312,522.87		75-R3	0	4,253	1.36		75-R3	0	4,282	1.37	(29)	
	TOTAL TRANSMISSION PLANT	**2,555,572,839.38**				**57,110,744**	**2.23**				**48,603,170**	**1.90**	**8,507,574**	**Increased negative net salvage for a few acounts**
	DISTRIBUTION PLANT													
361.00	STRUCTURES AND IMPROVEMENTS	127,079,158.04		60-R2	(15)	2,021,366	1.59		60-R2	(15)	1,931,603	1.52	89,763	
362.00	STATION EQUIPMENT	683,055,387.27		48-R1	(15)	15,332,138	2.24		46-R1	(15)	15,915,191	2.33	(583,053)	
364.00	POLES, TOWERS AND FIXTURES	855,785,431.01		45-R2.5	(100)	33,556,194	3.92		45-R2.5	(100)	33,803,525	3.95	(247,331)	
365.00	OVERHEAD CONDUCTORS AND DEVICES	1,208,423,459.24		45-R1	(30)	24,922,045	2.06		44-R1.5	(30)	25,981,104	2.15	(1,059,059)	
366.00	UNDERGROUND CONDUIT	199,779,066.87		46-S2.5	(15)	4,725,775	2.37		45-S2.5	(10)	4,515,007	2.26	210,768	
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1,134,635,170.25		42-S2	(5)	18,411,036	1.62		40-S2	(5)	19,969,579	1.76	(1,558,543)	
368.00	LINE TRANSFORMERS	1,131,254,323.64		40-R2	(5)	27,806,592	2.46		39-R2	(5)	28,733,860	2.54	(927,268)	
369.00	SERVICES	681,775,180.43		55-R3	(20)	10,868,784	1.59		42-R3	(10)	13,362,794	1.96	(2,494,010)	
370.00	METERING EQUIPMENT	51,889,323.64		28-R4	(10)	1,063,840	2.05		30-R4	(15)	1,769,426	3.41	(705,586)	
370.01	METERS	142,517,522.33		28-R4	(5)	7,007,351	**	12-2020	30-R4	(5)	5,572,435	3.91	1,434,916	
370.02	METERS - UOF	69,710,613.08		15-S2.5	0	4,645,856	6.66		17-S2.5	0	4,468,450	6.41	177,406	
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	318,551,648.97		26-S0.5	(10)	4,405,748	1.38		25-L1.5	(10)	3,663,344	1.15	742,404	
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	264,812,433.62		25-R1	(10)	12,840,929	4.85		30-R1	(10)	10,248,241	3.87	2,592,688	
	TOTAL DISTRIBUTION PLANT	**6,869,268,718.39**				**167,607,654**	**2.44**				**169,934,559**	**2.47**	**(2,326,905)**	**Longer average service lives for some accounts**

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	2018 STUDY PROBABLE RETIREMENT DATE	2018 STUDY SURVIVOR CURVE	2018 STUDY NET SALVAGE PERCENT	2018 STUDY CALCULATED ANNUAL ACCRUAL AMOUNT	2018 STUDY CALCULATED ANNUAL ACCRUAL RATE	2016 STUDY (SETTLEMENT) PROBABLE RETIREMENT DATE	2016 STUDY (SETTLEMENT) SURVIVOR CURVE	2016 STUDY (SETTLEMENT) NET SALVAGE PERCENT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL AMOUNT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL INCREASE/(DECREASE)	REASON
	(1)	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(10)	(11)	(12)=(2)*(9)	(13)	(14)=(6)-(12)	(15)
	GENERAL PLANT													
390.00	STRUCTURES AND IMPROVEMENTS	156,446,136.21		45-R1.5	(5)	3,805,402	2.43		45-R1.5	(5)	3,785,996	2.42	19,406	
391.00	OFFICE FURNITURE AND EQUIPMENT													
	FULLY ACCRUED	10,200,214.55		FULLY ACCRUED		0	-		FULLY ACCRUED		0	-	0	
	AMORTIZED	14,520,609.30		15-SQ	0	968,950	6.67		20-SQ	0	726,030	5.00	242,920	
	TOTAL OFFICE FURNITURE AND EQUIPMENT	24,720,823.85				968,950	3.92				726,030	2.94	242,920	
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP	61,586,228.38		8-SQ	0	7,696,591	12.50		8-SQ	0	7,696,591	12.50	0	
392.00	TRANSPORTATION EQUIPMENT	69,975,818.26		11-L2	15	4,493,909	6.42		11-L2	10	7,200,512	10.29	(2,706,603)	
393.00	STORES EQUIPMENT	2,059,932.97		20-SQ	0	102,894	5.00		20-SQ	0	102,894	5.00	0	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	90,247,659.07		20-SQ	0	4,508,503	5.00		20-SQ	0	4,508,503	5.00	0	
395.00	LABORATORY EQUIPMENT	6,739,788.51		15-SQ	0	449,309	6.67		15-SQ	0	449,309	6.67	0	
396.00	POWER OPERATED EQUIPMENT	5,679,686.30		12-S6	0	412,343	7.26		12-S6	0	340,213	5.99	72,130	
397.00	COMMUNICATION EQUIPMENT													
	FULLY ACCRUED	59,435,956.41		FULLY ACCRUED		0	-		FULLY ACCRUED		0	-	0	
	AMORTIZED	120,535,862.75		10-SQ	0	12,049,716	10.00		20-SQ	0	6,026,793	5.00	6,022,923	
	TOTAL COMMUNICATION EQUIPMENT	179,971,819.16				12,049,716	6.70				6,026,793	3.35	6,022,923	
398.00	MISCELLANEOUS EQUIPMENT	23,040,257.68		20-SQ	0	1,150,868	5.00		20-SQ	0	1,150,868	5.00	0	
	TOTAL GENERAL PLANT	**620,468,150.39**				**35,638,485**	**5.74**				**31,987,709**	**5.16**	**3,650,776**	
	TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT	**10,045,309,708.16**				**260,356,883**	**2.59**				**250,525,438**	**2.49**	**9,831,445**	**Updated amortization periods**
	DEPRECIABLE LAND RIGHTS													
310.00	LAND RIGHTS													
	ASHEVILLE UNIT 1	919,201.95	12-2027	100-R4 *	0	0	-	12-2027	100-R4 *	0	0	-	0	
	MAYO UNIT 1	3,577,117.54	06-2029	100-R4 *	0	34,725	0.97	06-2035	100-R4 *	0	27,902	0.78	6,823	
	ROXBORO UNIT 1	1,827,202.76	06-2028	100-R4 *	0	0	-	06-2028	100-R4 *	0	0	-	0	
	ROXBORO UNIT 3	3,037,934.25	06-2029	100-R4 *	0	0	-	06-2033	100-R4 *	0	0	-	0	
	TOTAL ACCOUNT 310	9,361,456.50				34,725	0.37				27,902	0.30	6,823	
320.00	LAND RIGHTS													
	HARRIS UNIT 1	49,809,293.03	10-2046	100-R4 *	0	601,134	1.21	10-2046	100-R4 *	0	602,692	1.21	(1,558)	
	ROBINSON UNIT 2	315,919.74	07-2030	100-R4 *	0	0	-	07-2030	100-R4 *	0	0	-	0	
	TOTAL LAND RIGHTS	50,125,212.77				601,134	1.20				602,692	1.20	(1,558)	
320.10	RIGHTS OF WAY													
	BRUNSWICK UNIT 1	9,724.11	09-2036	100-R4 *	0	90	0.93	09-2036	100-R4 *	0	87	0.89	3	
	BRUNSWICK UNIT 2	51,363.07	12-2034	100-R4 *	0	88	0.17	12-2034	100-R4 *	0	87	0.17	1	
	ROBINSON UNIT 2	6,141.10	07-2030	100-R4 *	0	0	-	07-2030	100-R4 *	0	0	-	0	
	TOTAL RIGHTS OF WAY	67,228.28				178	0.26				174	0.26	4	
	TOTAL ACCOUNT 320	50,192,441.05				601,312	1.20				602,866	1.20	(1,554)	
330.00	LAND RIGHTS													
	WALTERS	80,796.94	06-2034	110-R4 *	0	2,160	2.67	06-2034	110-R4 *	0	2,206	2.73	(46)	
330.10	RIGHTS OF WAY													
	BLEWETT	9,598.14	06-2055	110-R4 *	0	195	2.03	06-2055	110-R4 *	0	213	2.22	(18)	
	MARSHALL	3,728.53	06-2035	110-R4 *	0	98	2.63	06-2035	110-R4 *	0	105	2.82	(7)	
	TILLERY	19,764.49	06-2055	110-R4 *	0	261	1.32	06-2055	110-R4 *	0	279	1.41	(18)	
	WALTERS	33,333.15	06-2034	110-R4 *	0	887	2.66	06-2034	110-R4 *	0	903	2.71	(16)	
	TOTAL RIGHTS OF WAY	66,424.31				1,441	2.17				1,500	2.26	(59)	
	TOTAL ACCOUNT 330	147,221.25				3,601	2.45				3,706	2.52	(105)	
340.00	LAND RIGHTS													
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	2,048,655.08	06-2040	60-R4 *	0	49,114	2.40	06-2040	60-R4 *	0	51,421	2.51	(2,307)	
340.10	RIGHTS OF WAY													
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	2,532,367.27	06-2040	60-R4 *	0	67,739	2.67	06-2040	60-R4 *	0	69,893	2.76	(2,154)	
	TOTAL ACCOUNT 340.1	4,581,022.35				116,853	2.55				121,314	2.65	(4,461)	

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	2018 STUDY PROBABLE RETIREMENT DATE	2018 STUDY SURVIVOR CURVE	2018 STUDY NET SALVAGE PERCENT	2018 STUDY CALCULATED ANNUAL ACCRUAL AMOUNT	2018 STUDY CALCULATED ANNUAL ACCRUAL RATE	2016 STUDY (SETTLEMENT) PROBABLE RETIREMENT DATE	2016 STUDY (SETTLEMENT) SURVIVOR CURVE	2016 STUDY (SETTLEMENT) NET SALVAGE PERCENT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL AMOUNT	2016 STUDY (SETTLEMENT) CALCULATED ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL INCREASE/(DECREASE)	REASON
	(1)	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(10)	(11)	(12)=(2)*(9)	(13)	(14)=(6)-(12)	(15)
350.10	RIGHTS OF WAY	176,749,823.75		75-R3	0	2,039,608	1.15		75-R3	0	2,032,623	1.15	6,985	
360.00	LAND RIGHTS	107,521.37		65-R3	0	1,586	1.48		65-R3	0	1,602	1.49	(16)	
360.10	RIGHTS OF WAY	23,908,367.28		65-R3	0	298,919	1.25		65-R3	0	306,027	1.28	(7,108)	
389.10	RIGHTS OF WAY	51,783.33		60-R3	0	27,147	52.42		60-R3	0	26,674	51.51	473	
	TOTAL DEPRECIABLE LAND RIGHTS	**265,099,636.88**				**3,123,751**	**1.18**				**3,122,714**	**1.18**	**1,037**	
	TOTAL ELECTRIC PLANT	**26,397,951,517.28**				**931,854,218**	**3.53**				**792,895,437**	**3.00**	**138,958,781**	
	RESERVE ADJUSTMENT FOR AMORTIZATION													
391.00	OFFICE FURNITURE AND EQUIPMENT					3,426,096 ***					2,640,179 ***		785,917	
393.00	STORES EQUIPMENT					152,417 ***					172,193 ***		(19,776)	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					2,277,657 ***					2,051,679 ***		225,978	
395.00	LABORATORY EQUIPMENT					(79,664) ***					(53,710) ***		(25,954)	
397.00	COMMUNICATION EQUIPMENT					11,355,498 ***					2,599,760 ***		8,755,738	
398.00	MISCELLANEOUS EQUIPMENT					1,397,290 ***					1,574,923 ***		(177,633)	
	RESERVE ADJUSTMENT FOR AMORTIZATION					**18,529,294**					**8,985,024**		**9,544,270**	
	TOTAL DEPRECIABLE ELECTRIC PLANT	**26,397,951,517.28**				**950,383,512**					**801,880,461**		**148,503,050**	

NONDEPRECIABLE AND ACCOUNTS NOT STUDIED

NONDEPRECIABLE ACCOUNTS

301.00	ORGANIZATION	717,237.36
302.00	FRANCHISE	59,871,453.31
303.00	SOFTWARE	466,781,699.76
310.00	LAND	23,302,268.83
311.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT	248,681.03
317.00	ARO - STEAM	827,197,087.81
320.00	LAND	18,165,996.67
321.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE	1,854,278.73
326.00	ARO - NUCLEAR	876,137,782.45
330.00	LAND	2,681,695.37
331.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT	245,662.37
337.00	ARO - HYDRO	1,734,119.29
340.00	LAND	5,421,028.49
341.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE	105,999,098.00
347.20	ARO - OTHER PRODUCTION - SOLAR	7,642,438.48
350.00	LAND	14,066,210.40
352.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE	18,335,571.33
360.00	LAND	51,479,536.91
389.00	LAND	8,096,305.23
390.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE	10,359,698.41
399.00	ARO - GENERAL	2,717,587.67
	TOTAL NONDEPRECIABLE ACCOUNTS	2,503,055,437.90
	RETIRED PLANTS	
	CAPE FEAR	(1,328.95)
	ROBINSON ICT	
	ROXBORO ICT	
	TOTAL RETIRED PLANTS	(1,328.95)

I/A

DUKE ENERGY PROGRESS

COMPARISON OF PROPROSED PARAMETERS TO CURRENLTY APPROVED PARAMTERS

		2018 STUDY					2016 STUDY (SETTLEMENT)						
ACCOUNT (1)	**ORIGINAL COST AS OF DECEMBER 31, 2018 (2)**	**PROBABLE RETIREMENT DATE (3)**	**SURVIVOR CURVE (4)**	**NET SALVAGE PERCENT (5)**	**CALCULATED ANNUAL ACCRUAL AMOUNT (6)**	**CALCULATED ANNUAL ACCRUAL RATE (8)**	**PROBABLE RETIREMENT DATE (9)**	**SURVIVOR CURVE (10)**	**NET SALVAGE PERCENT (11)**	**CALCULATED ANNUAL ACCRUAL AMOUNT (12)=(2)*(9)**	**CALCULATED ANNUAL ACCRUAL RATE (13)**	**ANNUAL ACCRUAL INCREASE/(DECREASE) (14)=(6)-(12)**	**REASON (15)**
MISCELLANEOUS													
UNSPECIFIED													
NON-UTILITY													
HARRIS ACCELERATED DEPRECIATION													
CPL DECOMM													
RATE DIFFERENCE													
ARO													
ARO CONTRA COR													
OTHER (NO ACCOUNT ON 1085 PROVIDED)													
TOTAL MISCELLANEOUS	0.00												
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED	**2,503,054,108.95**												
TOTAL PLANT	**28,901,005,626.23**												

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.
** Annual Accrual Amount calculated based on remaining amortization period of 9.71 years (March 2028 which is 10 years from implementation).
*** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting.

Accrual rates for the Asheville Combined Cycle Plant when placed in service by November 2019 will be as follows:

Account	Rate
341.00	2.87
342.00	2.93
343.00	3.78
343.10	10.68
344.00	2.85
345.00	2.93
346.00	3.63

Accrual rates for new Battery Storage Assets based on a 15-L3 survivor curve and 0% net salvage will be as follows:

Account	Rate
348.00	6.90
351.00	6.90
363.00	6.90

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-3

Excerpts from DEP's 2019 IRP

I/A

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INTEGRATED RESOURCE PLAN UPDATE REPORT

2019

PUBLIC

2. 2019 IRP SUMMARY

Each year, as required by the NCUC and the PSCSC, DEP submits an IRP detailing projected infrastructure needed to meet the forecasted electricity requirements for its customers over the next 15 years. The 2019 IRP is the best projection of how the Company's capacity and energy portfolio is expected to evolve over the next 15 years, based on current data assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, environmental regulations, technology cost and performance characteristics and other outside factors change.

The proposed plan will meet the following objectives:

- Provide reliable electricity throughout the year, especially during periods of high peak demand such as cold winter mornings, by maintaining adequate planning reserve margins. Peak demand refers to the highest amount of electricity being consumed for any given hour across DEP's entire system.
- Select new resources at the lowest reasonable cost to customers. These resources include a balance of EE, DSM, renewable resources, battery storage and natural gas generation.
- Improve the environmental footprint of the portfolio by meeting or exceeding all federal, state and local environmental regulations. Furthermore, Duke Energy Corporation is committed to reducing its carbon emissions. Over the next decade, we are on track in the Carolinas to reduce carbon emissions by over 50 percent relative to a 2005 baseline level. Beyond 2030 even further reductions are attainable with continued technology development in the areas of carbon free generation and energy storage.

As 2019 is an update year, DEP developed two cases which reflect updates to the 2018 IRP Base Case. The first case, or the "Base Case," is an update to the presented base case in the 2018 IRP, which includes the expectation of future carbon legislation. Additionally, a "No Carbon Case" was developed in which no carbon legislation is considered. All results presented in this IRP represent the Base Case, unless otherwise noted. DEP has updated several key planning assumptions such as technology cost assumptions, fuel prices, renewable generation projections and the DEP load forecast.

As shown in the 2019 IRP Base Case, projected incremental needs are driven by load growth, contract expirations and the retirement of aging coal-fired and natural gas/oil resources. Of note, DEP has an increased load forecast relative to the prior IRP filing. A more detailed discussion of the load forecast can be found in Chapter 5. This increased forecast, coupled with contract

3. IRP PROCESS OVERVIEW

To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, the Company develops a load forecast of cumulative energy sales and hourly peak demands. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning reserve margin.

The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchase power contracts, is measured against the total resource need. Any deficit in future years will be met with a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements.

Growth in Peak Demand and Energy Consumption	+	**Resource Retirements Contract Expirations**	=	**New Resource Needs**

It should be noted that DEP considers the non-firm energy purchases and sales associated with the JDA with DEC in the development of its independent Base Case. To accomplish this, DEP and DEC plans are determined simultaneously to minimize revenue requirements of the combined jointly-dispatched system while maintaining independent reserve margins for each company.

DEP's IRP includes new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study in 2016 demonstrated the need to include winter peak planning in the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. The study also incorporated the expected significant growth in solar facilities that provide valuable assistance in meeting summer afternoon peak demands on the system but do little to assist in meeting demand for power on cold winter mornings. Based on results of the reliability study, DEP is utilizing a winter planning reserve margin of 17% in its planning process.

For the 2019 Update IRP, the Company presents a Base Case with a carbon tax beginning in 2025. However, remaining consistent with the Commission's Order to both include and exclude costs associated with carbon regulation, the current assumption of a carbon tax is intended to serve as a placeholder for some form of potential future carbon regulation.[1] An additional case assuming no carbon legislation was also developed.

While future carbon legislation is unknown, the Company feels that it is prudent to continue to plan for this scenario, as well as other potential future scenarios. Furthermore, a primary focus of this update IRP is the Short-Term Action Plan (STAP), which covers the period 2020 to 2024. It was determined that the inclusion of the carbon tax did not have a significant impact on the STAP, and therefore the majority of the data presented in this report represents the Base Case.

Figure 3-A represents a simplified overview of the resource planning process in the update years (odd years) of the IRP cycle.

[1] "Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans"; NCUC Docket No. E-100, Sub 147; p. 35

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-4

DEP Response to FPWC Data Request No. 1-23

Duke Energy Progress
Response to
Fayetteville Public Works Commission Data Request
Data Request No. 1

Docket No. E-2, Sub 1219

Date of Request: December 16, 2019
Date of Response: January 6, 2020

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to FPWC Data Request No. 1-23, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to FPWC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

FPWC
Data Request No. 1
DEP Docket No. E-2, Sub 1219
Item No. 1-23
Page 1 of 1

Request:

Referring to Direct Testimony of DEP witness Stephen G. De May, page 7, lines 18-20, please explain in detail the basis and provide supporting documentation for the conclusion that "making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now…".

Response:

As Witness De May testifies in his direct testimony, as part of the strategy to reduce the Company's reliance on coal, DEP took a fresh look at the viability of several of DEP's coal-fired plants and concluded that making shifts in the expected remaining depreciable lives of some of the existing coal-fired assets is a reasonable action to take now while the Company continues to monitor the changing industry landscape and market forces. Through a Present Value of Revenue Requirements ("PVRR") analysis, the Company determined that the impact of early retirement of these units would be better than, or near, break-even versus continuing to run to the original retirement dates for these units in the majority of the scenarios analyzed. Given the changing industry landscape and market forces, and the favorable PVRR analysis, the Company determined the acceleration of these assets was reasonable.

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-5

Duke Energy response to certain NCUC Questions in its August 27, 2019 Order Accepting Integrated Resource Plans

I/A

Lawrence B. Somers
Deputy General Counsel

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DUKE ENERGY®

November 4, 2019

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions in August 27, 2019 Order Docket No. E-100, Sub 157

Dear Ms. Campbell:

I enclose Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's (collectively, the "Companies") Response to questions and requests for information contained in the Commission's August 27, 2019 *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, for filing in connection with the referenced matter.

Portions of the response to Questions 1.a., 1.i, 4.a. and 4.b. contain confidential information and are being filed under seal. The table in the Question 1.a response contains confidential business and technical information which the Companies have designated as "trade secrets" under N.C. Gen. Stat. §66-152(3). The information in the Question 1.i response contains commercially-sensitive information regarding wholesale contracts and needs while the related market solicitation is still underway. The information in Quesiton 4.a. and 4.b. responses contain proprietary confidential cost information and analysis related to an open-market solicitation. If this trade secret and commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to customers. The Companies respectfully request that the commercially sensitive and trade secret information be treated confidentially pursuant to N.C. Gen. Stat. 132-1.2. The Companies will provide a copy of the confidential information to parties to this proceeding upon execution of an appropriate confidentiality agreement.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosures

cc: Parties of Record

100, Sub 158, the Companies believe that the forecast of DSM program savings are reasonable and accurately reflect a continued effort to add new customers; however, the forecast recognizes customer response to these programs has been limited, despite targeted and ongoing efforts to increase participation.

The residential DEP EnergyWise Home program currently offers winter measures (Hot Water Heaters & Heat Pump Heat Strips) in its Western region in and around Asheville. These measures have been in place for 10 years and have been marketed aggressively with direct mail, email, outbound calling, and door-to-door canvassing. Over that 10-year period, the program has achieved 15 MW. Assuming the same level of achievable potential in the rest of DEP and DEC, a reasonable estimate of residential winter DSM would be 150 MW in each jurisdiction in 10 years, which would only be true if those measures remained cost-effective into the future.

Moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is difficult to achieve for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation. The Companies note their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and continue to work toward implementation of those programs.

3. DEC's and DEP's most current strategic plans to reduce carbon dioxide (CO2) emissions, including:

(a) The implementation plan (including CO2 glide path) that results in the attainment of DEC's and DEP's most current goals for reductions in CO2 emissions.

Response:

In mid-September 2019, Duke Energy Corporation announced its new, enterprise-wide climate strategy, including updating its CO_2 reduction goals to at least 50% reduction by 2030 and achieving net-zero for electricity generation by 2050. Both goals are reductions from 2005 CO_2 levels. The specific trajectory for each Duke Energy utility contributions for achieving those goals will vary by jurisdiction.

For DEC and DEP, the base case in both the 2018 IRP and the 2019 IRP Update plans achieves at least 50% CO_2 reduction by 2030, which is aligned with Duke Energy

Corporation's current climate strategy. However, DEC and DEP plan to work with regulators, customers and other stakeholders to determine how best to achieve reductions greater than 50% by 2030 and ultimately achieve net-zero emission by 2050 in a manner that balances reliability, affordability and sustainability.

(b) Modelling of the carbon reduction goals in the draft Clean Energy Plan released for public comment on August 16, 2019, by the North Carolina Department of Environmental Quality and Duke's current carbon reduction plan. The modelling should not only show the resource portfolio needed to achieve these goals but should also show any cost differentials (increases or savings) from the base case and the preferred case. In modelling cost differentials, the plans should include anticipated costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants and anticipated cost savings attributable to earlier retirement of such plants.

Response:

Since the Commission issued its August 27, 2019 Order accepting the 2018 IRPs and requesting this additional information, the North Carolina Department of Environmental Quality (DEQ) released their "final" version of the Clean Energy Plan. The final plan, released on September 27, 2019, included several significant changes from the "draft" Clean Energy Plan released on August 16, 2019. Two of these changes were:

1. A shift in focus from CO_2 emissions to Greenhouse Gas (GHG) emissions, and
2. A narrowing of the emissions reduction target from a 60% - 70% reduction in CO_2 emissions to a 2030 GHG emissions reduction target of 70%.

In order to model plans to achieve the full 70% reduction in GHG emissions, the Companies would first need to work with DEQ to understand:

1. How are GHGs being defined (what is included, what is not)?
2. What is the baseline (from what levels are reductions required)?
3. What are DEC and DEP's fair share of the statewide reductions? and
4. How is DEQ considering tracking GHG emissions reductions?

When only considering CO_2 emissions, there are many potential paths that could be taken to move closer to a 70% reduction target by 2030, and the Companies look forward to working with DEQ and other stakeholders on the best way to achieve these goals in a manner that balances reliability, affordability and sustainability. Given there are multiple paths, and uncertainties around how GHG is defined, the Companies have not developed a preferred plan for how these GHG emissions reduction targets could be

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met. However, in response to the request by the Commission, the Companies are presenting two potential, illustrative scenarios that would move the Companies closer to achieving 70% CO_2 reduction target by 2030, utilizing a 2005 baseline. These reductions are achieved by increasing the pace of coal plant retirements while significantly increasing the Companies' mix of renewables (including wind generation), battery storage, energy efficiency, and combustion turbine (CT) generation.

The scenarios presented do not fully account for the real-world challenges that would be faced in adding a significant number of new grid resources in a short amount of time. Issues not addressed, but required to implement this pace of system transformation, include physical and regulatory challenges affecting the time to construct new assets and their associated interconnection and system upgrade requirements. Implementation would require addressing issues in the areas of supply-chain, siting, permitting, right-of-way acquisition, transmission queue studies, comprehensive network upgrades, gas pipeline expansion and acquiring facility certificates of public convenience and necessity (CPCN) for all new facilities. At a minimum, existing legislative and regulatory processes governing resource additions (including, but not limited to, siting, permitting, and CPCN processes). may be needed to be modified to accommodate the pace of transition outlined in the scenarios studied.

Notwithstanding implementation challenges, the scenarios do provide a high level economic assessment that accounts for a potential decline in system operating costs, including fuel costs, as more renewables and more efficient gas generation are added to the system, decreased or eliminated expenses associated with ongoing coal operations including anticipated reductions in costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants. To be clear, coal ash costs associated with ash that was generated prior to this study are included in the base and change cases and early retirement of operating coal plants does not impact those costs. The scenarios account for the estimated capital and operating costs associated with accelerating the replacement generation, storage and DSM programs. However, given the magnitude of these projected system changes in the relatively short time span, it is extremely difficult to predict the total network transmission costs needed to implement these changes. As such, these costs have been excluded and could materially impact the economics in the presented scenarios. The Atlantic Coast Pipeline (ACP) is already considered in the base case, but the scenarios do include the incremental cost of pipeline infrastructure to support incremental gas generation above what is in the base case. Finally, the economic analysis also assumes significant reductions in the installed cost of renewable and storage resources compared to today's levels, which help to lessen the economic impact of the scenarios.

The Companies are presenting a comparison of two potential paths that achieve 60% and

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64% CO_2 emission reductions by 2030 versus the "Base Case" plan that achieves 51% CO_2 emission reductions. Again, these are not the Companies' actual plans but rather are simply intended to provide context to the potential impacts of achieving closer to 70% CO_2 reduction by 2030. Because DEC and DEP serve customers in both North Carolina and South Carolina through the respective integrated Carolinas systems, the emissions reductions shown in the cases below are total system reductions across the two utilities and are not specific to North Carolina. Additionally, the Base Case is derived from the 2018 IRP Joint Plan scenario that was developed to show the impacts of DEC and DEP jointly planning for future capacity needs. This case was updated with inputs from the 2019 IRP Update including fuel prices and load forecast updates. A description of the 3 cases is presented below in Table 1.

Table 1: Resource Mix at Varying Levels of CO_2 Reduction

	Base Case	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
CO2 Reduction vs 2005 Baseline	51%	60%	64%
Coal Retired by 2030, MW and as % of Coal Generation Available as of October 1, 2019	2,567 MW (25%)	6,028 MW (58%)[1]	10,415 MW (100%)[2]
Generation Mix by 2030, MW and % of Total Capacity in 2030			
Total Nameplate Solar	7,543 *(15%)*	8,212 *(15%)*	9,643 *(18%)*
Total Storage[3]	452 *(1%)*	1,710 *(3%)*	2,984[4] *(5%)*
Total Wind, MW[5]	0 *(0%)*	750 *(1%)*	750 *(1%)*
Incremental EE/DSM, MW[6]	1,979 *(4%)*	2,942 *(5%)*	2,942 *(5%)*
New CC, MW	4,023 *(8%)*	4,023 *(8%)*	4,023 *(7%)*
New CT, MW	1,880 *(4%)*	3,760 *(7%)*	6,110 *(11%)*
Other Renewables & Hydro	1,365 *(3%)*	1,365 *(3%)*	1,365 *(3%)*

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	Base Case	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
Existing Nuclear	11,188 *(22%)*	11,188 *(21%)*	11,188 *(21%)*
Existing Pumped Storage	2,400 *(5%)*	2,400 *(4%)*	2,400 *(4%)*
Existing & Designated CC/CHP	5,836 *(11%)*	5,836 *(11%)*	5,836 *(11%)*
Existing & Designated CT	6,519 *(13%)*	6,519 *(12%)*	6,519 *(12%)*
Coal	7,848 *(15%)*	4,387 *(8%)*	0 *(0%)*
Conventional Purchases	528 *(1%)*	528 *(1%)*	528 *(1%)*

Notes:

1. Includes Allen 1-5, Cliffside 5, and Marshall 1&2 in DEC and Asheville 1&2, Mayo, and Roxboro 1-4 in DEP.
2. Includes all units in Note 1, along with Belews Creek and Marshall 3&4 in DEC. Additionally, Cliffside 6 is 100% gas fired from 2030 and beyond.
3. Values represent total usable capacity. A 4-hour battery storage is assumed to provide 80% contribution to winter peak. As level of 4-hour storage increases, contribution to winter peak may be reduced significantly.
4. Assumes approximately 1,300 MW of existing solar resources install storage behind existing solar inverter along with a portion of new build solar also installing storage behind solar inverter in "Retire All Coal by 2030" case.
5. Assumes "on-shore" wind. Does not include potential for off-shore generated wind energy.
6. EE MWs based on Market Potential Study included in 2018 IRP. Study will be updated for the 2020 Comprehensive IRP.

The following table summarizes the preliminary economic analysis conducted that compares the two potential illustrative scenarios to the base case. Results are shown by estimated present value revenue requirements (PVRR) through 2034 and are presented in 2019 dollars. **PLEASE NOTE:** These estimates do **NOT** include the impact of network transmission upgrades necessary to support the system which would likely

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increase the total PVRR significantly. This preliminary, high-level analysis shows the estimated incremental PVRR for each of these two scenarios ranges from \$2.0B to \$5.1B when compared to the base case excluding transmission costs.

It is important to recognize that capital costs in the PVRR calculation are based on real-levelized cash flows through 2034, and are not suitable for directly calculating rate impacts. However, when considering nominal cash flows, the PVRR below represents an acceleration of \$6 Billion to \$13 Billion of potential capital spend into the 2020s. This acceleration of capital yields an average annual operating cost savings, including fuel savings and avoided costs relative to on-going coal plant operations, of approximately \$170 Million to \$340 Million through 2030 when compared to the base case.

Table 2: Approximate PVRR through 2034 (2019\$)
(Negative numbers shown in parentheses represent a cost savings vs the base case)

	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
CO_2 Reduction vs 2005 Baseline	60%	64%
System Production Cost Savings (fuel, start costs, VOM)	(\$2,100,000,000)	(\$3,000,000,000)
Incremental Solar & Storage Capital & FOM	\$700,000,000	\$4,800,000,000
Incremental Grid-Tied Storage Capital & FOM	\$1,700,000,000	\$1,700,000,000
Incremental Wind Capital & FOM	\$600,000,000	\$600,000,000
Incremental EE Cost	\$1,300,000,000	\$1,300,000,000
Incremental Gas Generation Capital & FOM	\$200,000,000	\$200,000,000
Coal Plant On-going Capital, Environmental Capital & FOM Savings	(\$300,000,000)	(\$1,100,000,000)
Total (+ Cost vs Base / - Savings vs Base)	\$2,000,000,000	\$5,100,000,000

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	60% CO_2 Reduction by 2030	64% CO_2 Reduction by 2030
Approximate % PVRR Increase vs Base Case	5%	12%

Notes:

- Costs are only calculated through 2034, as such, the lifetime costs and benefits of the assets are not fully captured in this analysis.
- Analysis did not include increased transmission interconnection or system upgrade costs associated with replacement generation.
- For ease of calculation, all incremental generation additions are assumed to be utility owned and do not reflect any assumptions regarding future third-party ownership or PURPA avoided cost assumptions.
- EE costs are based on the 2018 Market Potential Study which is being updated and will be included in the 2020 IRP.
- Includes a 35% reduction in solar PV costs (real 2019$) from 2019 through 2028.
- Includes a 50% reduction in battery storage costs (real 2019$) from 2019 through 2028.

(c) A comparison of DEC's and DEP's most current plans for CO2 emission reductions to the Governor's Executive Order No. 80 which states that "The State of North Carolina will strive to accomplish the following by 2025: a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels."

Response:

Similar to the response in Part (b), Executive Order 80 focuses on GHG emissions and the Companies would need to work with DEQ to understand:

- How are GHGs being defined (what is included, what is not)
- What is the baseline (from what levels are reductions required)
- What is Duke Energy's fair share of the state-wide reductions, and
- How they are considering tracking GHG emissions reductions.

However, in terms of CO_2 emissions, the Company's base case achieves at least a 50% CO_2 reduction below 2005 levels in 2025.

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-6

Impacts of Accelerating Retirement Dates for Mayo, Roxboro Unit 3, and Roxboro Unit 4

SPANOS Table 1 (As Filed)

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	ASHEVILLE UNIT 1	12-2027	100-R2.5 *	(4)	42,616,358.21	39,177,778	5,143,234	573,609	1.35	9.0
	ASHEVILLE UNIT 2	12-2027	100-R2.5 *	(4)	42,579,071.25	31,072,574	13,209,660	1,473,445	3.46	9.0
	MAYO UNIT 1	06-2029	100-R2.5 *	(4)	170,239,859.39	126,127,393	50,922,061	4,879,145	2.87	10.4
	ROXBORO UNIT 1	06-2028	100-R2.5 *	(5)	17,139,904.05	14,127,970	3,868,930	408,845	2.39	9.5
	ROXBORO UNIT 2	06-2028	100-R2.5 *	(5)	5,512,432.01	3,928,468	1,859,586	196,628	3.57	9.5
	ROXBORO UNIT 3	06-2029	100-R2.5 *	(5)	37,367,402.39	35,337,975	3,897,798	372,911	1.00	10.5
	ROXBORO UNIT 4	06-2029	100-R2.5 *	(5)	19,539,071.49	9,595,015	10,921,010	1,048,303	5.37	10.4
	ROXBORO COMMON	06-2029	100-R2.5 *	(5)	193,990,592.95	49,894,500	153,795,623	14,718,151	7.59	10.4
	TOTAL STRUCTURES AND IMPROVEMENTS				528,984,691.74	309,261,673	243,617,902	23,671,037	4.47	10.3
312.00	BOILER PLANT EQUIPMENT									
	ASHEVILLE UNIT 1	12-2027	60-R1 *	(4)	149,655,719.36	93,325,565	62,316,384	7,121,696	4.76	8.8
	ASHEVILLE UNIT 2	12-2027	60-R1 *	(4)	145,625,344.87	110,436,602	41,013,757	4,682,918	3.22	8.8
	MAYO UNIT 1	06-2029	60-R1 *	(4)	832,479,002.87	354,948,282	510,829,881	50,461,597	6.06	10.1
	ROXBORO UNIT 1	06-2028	60-R1 *	(5)	212,902,505.83	87,482,059	136,065,572	14,793,592	6.95	9.2
	ROXBORO UNIT 2	06-2028	60-R1 *	(5)	309,506,429.33	168,229,667	156,752,084	17,017,838	5.50	9.2
	ROXBORO UNIT 3	06-2029	60-R1 *	(5)	333,830,832.31	118,836,753	231,685,621	22,920,294	6.87	10.1
	ROXBORO UNIT 4	06-2029	60-R1 *	(5)	404,141,708.49	275,790,947	148,557,847	14,572,511	3.61	10.2
	ROXBORO COMMON	06-2029	60-R1 *	(5)	320,174,907.77	168,313,679	167,869,974	16,435,758	5.13	10.2
	TOTAL BOILER PLANT EQUIPMENT				2,708,316,450.83	1,377,363,553	1,455,091,120	148,006,204	5.46	9.8
312.10	BOILER PLANT EQUIPMENT - SCR CATALYST									
	ASHEVILLE UNIT 1	12-2027	10-S1 *	0	3,957,262.78	4,500,630	(543,367)	0	-	-
	ASHEVILLE UNIT 2	12-2027	10-S1 *	0	1,798,265.75	1,961,047	(162,782)	0	-	-
	MAYO UNIT 1	06-2029	10-S1 *	0	7,428,602.62	7,594,648	(166,045)	0	-	-
	ROXBORO UNIT 1	06-2028	10-S1 *	0	7,925,144.00	8,427,153	(502,009)	0	-	-
	ROXBORO UNIT 2	06-2028	10-S1 *	0	5,857,261.54	6,103,037	(245,775)	0	-	-
	ROXBORO UNIT 3	06-2029	10-S1 *	0	6,541,925.15	4,994,846	1,547,079	245,298	3.75	6.3
	ROXBORO UNIT 4	06-2029	10-S1 *	0	7,261,916.42	8,154,038	(892,122)	0	-	-
	TOTAL BOILER PLANT EQUIPMENT - SCR CATALYST				40,770,378.26	41,735,399	(965,021)	245,298	0.60	(3.9)
314.00	TURBOGENERATOR UNITS									
	ASHEVILLE UNIT 1	12-2027	60-S0 *	(4)	18,830,227.72	7,586,897	11,996,540	1,378,245	7.32	8.7
	ASHEVILLE UNIT 2	12-2027	60-S0 *	(4)	13,968,640.50	13,145,255	1,382,131	155,826	1.12	8.9
	MAYO UNIT 1	06-2029	60-S0 *	(4)	109,608,959.00	65,409,412	48,583,905	4,863,907	4.44	10.0
	ROXBORO UNIT 1	06-2028	60-S0 *	(5)	45,628,567.76	18,857,340	29,052,656	3,153,178	6.91	9.2
	ROXBORO UNIT 2	06-2028	60-S0 *	(5)	44,959,643.18	15,793,614	31,414,011	3,418,913	7.60	9.2
	ROXBORO UNIT 3	06-2029	60-S0 *	(5)	73,030,422.44	30,051,305	46,630,638	4,601,862	6.30	10.1
	ROXBORO UNIT 4	06-2029	60-S0 *	(5)	69,565,691.07	35,567,696	37,476,280	3,723,176	5.35	10.1
	ROXBORO COMMON	06-2029	60-S0 *	(5)	458,890.76	337,291	144,545	14,425	3.14	10.0
	TOTAL TURBOGENERATOR UNITS				376,051,042.43	186,748,811	206,680,706	21,309,532	5.67	9.7
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	ASHEVILLE UNIT 1	12-2027	70-R1 *	(4)	17,304,563.70	10,105,982	7,890,765	896,804	5.18	8.8
	ASHEVILLE UNIT 2	12-2027	70-R1 *	(4)	10,774,312.04	11,377,112	(171,827)	0	-	-
	MAYO UNIT 1	06-2029	70-R1 *	(4)	66,829,604.18	32,728,460	36,774,329	3,607,025	5.40	10.2
	ROXBORO UNIT 1	06-2028	70-R1 *	(5)	27,911,638.64	9,388,873	19,918,347	2,151,100	7.71	9.3
	ROXBORO UNIT 2	06-2028	70-R1 *	(5)	24,223,049.38	17,239,203	8,194,999	883,710	3.65	9.3
	ROXBORO UNIT 3	06-2029	70-R1 *	(5)	42,579,385.55	15,020,156	29,688,199	2,913,552	6.84	10.2
	ROXBORO UNIT 4	06-2029	70-R1 *	(5)	43,547,824.88	20,360,939	25,364,277	2,486,371	5.71	10.2
	ROXBORO COMMON	06-2029	70-R1 *	(5)	23,722,266.18	7,276,792	17,631,587	1,723,633	7.27	10.2
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				256,892,644.55	123,497,516	145,290,676	14,662,195	5.71	9.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ASHEVILLE UNIT 1	12-2027	45-S0 *	(4)	10,334,480.63	4,727,909	6,019,951	695,241	6.73	8.7
	ASHEVILLE UNIT 2	12-2027	45-S0 *	(4)	5,120,201.92	4,538,194	786,816	91,397	1.79	8.6
	MAYO UNIT 1	06-2029	45-S0 *	(4)	13,338,741.21	5,584,869	8,287,422	840,910	6.30	9.9
	ROXBORO UNIT 1	06-2028	45-S0 *	(5)	4,072,524.77	1,719,045	2,557,106	281,244	6.91	9.1
	ROXBORO UNIT 2	06-2028	45-S0 *	(5)	4,425,440.03	2,695,586	1,951,126	214,299	4.84	9.1
	ROXBORO UNIT 3	06-2029	45-S0 *	(5)	4,581,632.45	2,143,896	2,666,819	270,285	5.90	9.9
	ROXBORO UNIT 4	06-2029	45-S0 *	(5)	5,430,383.41	2,700,578	3,001,325	308,691	5.68	9.7
	ROXBORO COMMON	06-2029	45-S0 *	(5)	20,631,298.87	5,918,365	15,744,498	1,574,562	7.63	10.0
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT				67,934,703.29	30,028,440	41,015,063	4,276,629	6.30	9.6
	TOTAL STEAM PRODUCTION PLANT				**3,978,949,911.10**	**2,068,635,392**	**2,090,730,446**	**212,170,895**	**5.33**	**9.9**

SPANOS Table 1 (As Filed)

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)		NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
	NUCLEAR PRODUCTION PLANT										
321.00	STRUCTURES AND IMPROVEMENTS										
	BRUNSWICK UNIT 1	09-2036	75-S1	*	(1)	423,009,418.66	182,352,007	244,887,506	14,175,485	3.35	17.3
	BRUNSWICK UNIT 2	12-2034	75-S1	*	(1)	397,968,469.79	223,090,544	178,857,611	11,520,013	2.89	15.5
	HARRIS UNIT 1	10-2046	75-S1	*	(2)	1,996,266,873.69	1,204,989,357	831,202,855	32,248,496	1.62	25.8
	HARRIS DISALLOWANCE	10-2046				(105,862,561.00)	(67,742,934)	(38,119,627)	(1,369,567)	1.29	27.8
	ROBINSON UNIT 2	07-2030	75-S1	*	(1)	373,649,660.90	190,668,370	186,717,788	16,338,445	4.37	11.4
	TOTAL STRUCTURES AND IMPROVEMENTS					3,085,031,862.04	1,733,357,343	1,403,546,133	72,912,872	2.36	19.2
322.00	REACTOR PLANT EQUIPMENT										
	BRUNSWICK UNIT 1	09-2036	52-R2	*	(1)	612,117,283.68	299,468,246	318,770,211	19,312,794	3.16	16.5
	BRUNSWICK UNIT 2	12-2034	52-R2	*	(1)	544,476,825.16	293,189,240	256,732,353	17,115,022	3.14	15.0
	HARRIS UNIT 1	10-2046	52-R2	*	(2)	1,075,559,612.15	425,966,772	671,104,032	28,850,918	2.68	23.3
	HARRIS DISALLOWANCE	10-2046				(132,409,445.00)	(84,730,657)	(47,678,788)	(1,713,010)	1.29	27.8
	ROBINSON UNIT 2	07-2030	52-R2	*	(1)	462,756,240.49	249,630,881	217,752,922	19,464,027	4.21	11.2
	TOTAL REACTOR PLANT EQUIPMENT					2,562,500,516.48	1,183,524,482	1,416,680,730	83,029,751	3.24	17.1
323.00	TURBOGENERATOR UNITS										
	BRUNSWICK UNIT 1	09-2036	40-S0	*	(1)	285,997,062.33	101,762,273	187,094,760	11,823,008	4.13	15.8
	BRUNSWICK UNIT 2	12-2034	40-S0	*	(1)	172,548,284.27	83,648,310	90,625,457	6,442,418	3.73	14.1
	HARRIS UNIT 1	10-2046	40-S0	*	(2)	535,687,360.49	148,284,568	398,116,540	17,371,808	3.24	22.9
	HARRIS DISALLOWANCE	10-2046				(610,466.00)	(390,646)	(219,820)	(7,898)	1.29	27.8
	ROBINSON UNIT 2	07-2030	40-S0	*	(1)	333,276,803.83	41,912,529	294,697,043	26,899,155	8.07	11.0
	TOTAL TURBOGENERATOR UNITS					1,326,899,044.92	375,217,034	970,313,980	62,528,491	4.71	15.5
324.00	ACCESSORY ELECTRIC EQUIPMENT										
	BRUNSWICK UNIT 1	09-2036	50-R2.5	*	(1)	161,647,774.74	48,960,985	114,303,267	6,821,086	4.22	16.8
	BRUNSWICK UNIT 2	12-2034	50-R2.5	*	(1)	210,342,927.28	83,854,412	128,591,944	8,431,189	4.01	15.3
	HARRIS UNIT 1	10-2046	50-R2.5	*	(2)	820,436,969.84	447,858,632	388,987,077	16,303,928	1.99	23.9
	HARRIS DISALLOWANCE	10-2046				(256,837,664.66)	(164,354,016)	(92,483,649)	(3,322,766)	1.29	27.8
	ROBINSON UNIT 2	07-2030	50-R2.5	*	(1)	279,070,966.07	77,699,673	204,162,003	17,942,656	6.43	11.4
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					1,214,660,973.27	494,019,687	743,560,642	46,176,093	3.80	16.1
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT										
	BRUNSWICK UNIT 1	09-2036	50-R1.5	*	(1)	201,192,590.16	72,402,768	130,801,748	7,865,762	3.91	16.6
	BRUNSWICK UNIT 2	12-2034	50-R1.5	*	(1)	68,906,220.33	31,605,240	37,990,042	2,534,043	3.68	15.0
	HARRIS UNIT 1	10-2046	50-R1.5	*	(2)	247,301,101.58	110,487,995	141,759,129	5,889,127	2.38	24.1
	HARRIS DISALLOWANCE	10-2046				(55,577,154.00)	(35,564,599)	(20,012,555)	(719,014)	1.29	27.8
	ROBINSON UNIT 2	07-2030	50-R1.5	*	(1)	190,043,010.80	57,228,953	134,714,488	12,040,133	6.34	11.2
	TOTAL MISCELLANEOUS PLANT EQUIPMENT					651,865,768.87	236,160,357	425,252,852	27,610,051	4.24	15.4
	TOTAL NUCLEAR PRODUCTION PLANT					**8,840,958,165.58**	**4,022,278,903**	**4,959,354,336**	**292,257,258**	**3.31**	**17.0**
	HYDRAULIC PRODUCTION PLANT										
331.00	STRUCTURES AND IMPROVEMENTS										
	BLEWETT	06-2055	110-R2	*	(33)	6,620,300.84	2,221,068	6,583,932	187,401	2.83	35.1
	MARSHALL	06-2035	110-R2	*	(16)	1,523,286.57	36,589	1,730,423	107,146	7.03	16.2
	TILLERY	06-2055	110-R2	*	(29)	6,634,057.32	1,449,284	7,108,649	202,328	3.05	35.1
	WALTERS	06-2034	110-R2	*	(6)	3,472,324.03	1,969,353	1,711,310	112,577	3.24	15.2
	TOTAL STRUCTURES AND IMPROVEMENTS					18,249,968.76	5,676,294	17,134,314	609,452	3.34	28.1
332.00	RESERVOIRS, DAMS AND WATERWAYS										
	BLEWETT	06-2055	120-R3	*	(33)	8,275,323.29	5,471,755	5,534,425	160,135	1.94	34.6
	MARSHALL	06-2035	120-R3	*	(16)	4,071,208.19	2,374,604	2,347,997	143,440	3.52	16.4
	TILLERY	06-2055	120-R3	*	(29)	6,796,645.31	4,942,178	3,825,494	110,074	1.62	34.8
	WALTERS	06-2034	120-R3	*	(6)	34,543,362.20	18,258,190	18,357,774	1,195,944	3.46	15.4
	TOTAL RESERVOIRS, DAMS AND WATERWAYS					53,686,538.99	31,046,729	30,065,690	1,609,593	3.00	18.7

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	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	BLEWETT	06-2055	75-R1.5 *	(33)	13,436,525.48	255,189	17,615,390	536,807	4.00	32.8
	MARSHALL	06-2035	75-R1.5 *	(16)	6,041,207.23	4,039,831	2,967,969	189,470	3.14	15.7
	TILLERY	06-2055	75-R1.5 *	(29)	14,142,264.87	1,061,347	17,182,175	530,595	3.75	32.4
	WALTERS	06-2034	75-R1.5 *	(6)	4,456,120.96	2,409,069	2,314,420	155,664	3.49	14.9
	TOTAL WATER WHEELS, TURBINES AND GENERATORS				38,076,118.54	7,765,436	40,079,954	1,412,536	3.71	28.4
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	BLEWETT	06-2055	55-R1 *	(33)	7,543,722.48	(213,543)	10,246,694	338,949	4.49	30.2
	MARSHALL	06-2035	55-R1 *	(16)	1,179,515.99	773,248	594,991	40,208	3.41	14.8
	TILLERY	06-2055	55-R1 *	(29)	3,853,242.31	944,048	4,026,634	137,612	3.57	29.3
	WALTERS	06-2034	55-R1 *	(6)	13,242,973.33	1,362,762	12,674,790	856,757	6.47	14.8
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				25,819,454.11	2,866,514	27,543,109	1,373,526	5.32	20.1
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	BLEWETT	06-2055	55-S0 *	(33)	1,826,329.58	422,693	2,006,325	66,903	3.66	30.0
	MARSHALL	06-2035	55-S0 *	(16)	200,696.66	66,551	166,257	10,921	5.44	15.2
	TILLERY	06-2055	55-S0 *	(29)	1,227,560.24	602,303	981,249	32,943	2.68	29.8
	WALTERS	06-2034	55-S0 *	(6)	1,756,787.00	448,826	1,413,368	96,765	5.51	14.6
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				5,011,373.48	1,540,374	4,567,199	207,532	4.14	22.0
336.00	ROADS, RAILROADS, AND BRIDGES									
	MARSHALL	06-2035	75-R3 *	(16)	12,946.58	9,238	5,780	364	2.81	15.9
	WALTERS	06-2034	75-R3 *	(6)	8,258.48	8,473	281	24	0.29	11.7
	TOTAL ROADS, RAILROADS, AND BRIDGES				21,205.06	17,711	6,061	388	1.83	15.6
	TOTAL HYDRAULIC PRODUCTION PLANT				**140,864,658.94**	**48,913,058**	**119,396,327**	**5,213,027**	**3.70**	**22.9**
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	ASHEVILLE IC TURBINE	06-2039	50-S1 *	(3)	31,762,836.46	15,086,579	17,629,142	975,677	3.07	18.1
	BLEWETT IC TURBINES	06-2024	50-S1 *	(7)	979,562.66	987,420	60,712	11,136	1.14	5.50
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-S1 *	(7)	362,282.66	1,161,265	(773,623)	0	-	-
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-S1 *	(7)	8,403,245.66	7,799,625	1,191,848	69,646	0.83	17.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-S1 *	(4)	9,013,914.23	4,506,042	4,868,429	254,463	2.82	19.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-S1 *	(4)	1,356,819.84	323,439	1,087,654	40,347	2.97	27.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-S1 *	(2)	19,344,678.47	7,843,041	11,888,531	579,000	2.99	20.5
	SUTTON BLACKSTART	06-2057	50-S1 *	(9)	11,574,792.86	4,616,347	8,000,177	231,353	2.00	34.6
	WEATHERSPOON IC TURBINES	06-2024	50-S1 *	(21)	3,568,977.41	3,833,880	484,582	92,356	2.59	5.2
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-S1 *	(4)	47,694,242.52	40,526,455	9,075,557	440,153	0.92	20.6
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-S1 *	(8)	40,103,160.35	7,907,269	35,404,144	1,232,177	3.07	28.7
	SUTTON COMBINED CYCLE	06-2053	50-S1 *	(3)	13,462,878.60	(1,895,584)	15,762,349	512,673	3.81	30.7
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-S1 *	(6)	25,476,302.18	7,358,309	19,646,572	711,705	2.79	27.6
	TOTAL STRUCTURES AND IMPROVEMENTS				213,103,693.90	100,054,088	124,326,074	5,150,686	2.42	24.1
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR									
	CAMP LEJUNE	06-2040	30-S2.5 *	(9)	26,130.74	1,617	26,865	1,307	5.00	20.6
	FAYETTEVILLE	06-2040	30-S2.5 *	(11)	3,957.51	248	4,145	204	5.15	20.3
	ELM CITY	06-2041	30-S2.5 *	(15)	3,925.80	248	4,267	203	5.17	21.0
	TOTAL STRUCTURES AND IMPROVEMENTS - SOLAR				34,014.05	2,113	35,277	1,714	5.04	20.6
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
	ASHEVILLE IC TURBINE	06-2039	45-R2 *	(3)	5,115,723.34	2,495,453	2,773,742	148,602	2.90	18.7
	BLEWETT IC TURBINES	06-2024	45-R2 *	(7)	413,479.62	403,237	39,186	7,229	1.75	5.4
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	45-R2 *	(7)	5,048,367.44	5,817,173	(415,419)	0	-	-
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	45-R2 *	(7)	7,243,963.20	5,872,288	1,878,753	108,699	1.50	17.3
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	45-R2 *	(4)	7,363,988.43	3,459,288	4,199,260	219,470	2.98	19.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	45-R2 *	(4)	1,461,178.80	360,131	1,159,495	43,476	2.98	26.7
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	45-R2 *	(2)	8,473,790.16	3,354,658	5,288,608	267,152	3.15	19.8
	SUTTON BLACKSTART	06-2057	45-R2 *	(9)	5,990,884.76	137,567	6,392,498	188,103	3.14	34.0
	WEATHERSPOON IC TURBINES	06-2024	45-R2 *	(21)	1,651,095.21	1,242,908	754,917	140,115	8.49	5.4
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	45-R2 *	(4)	13,523,522.65	5,631,253	8,433,211	405,772	3.00	20.8
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	45-R2 *	(8)	22,575,250.21	4,383,495	19,997,775	702,612	3.11	28.5
	SUTTON COMBINED CYCLE	06-2053	45-R2 *	(3)	19,656,537.55	(5,290,149)	25,536,382	835,790	4.25	30.6
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	45-R2 *	(6)	25,423,310.37	2,091,783	24,856,926	845,788	3.33	29.4
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES				123,941,091.74	29,959,084	100,895,334	3,912,808	3.16	25.8

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	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
343.00	PRIME MOVERS									
	ASHEVILLE IC TURBINE	06-2039	30-R0.5 *	(3)	51,871,873.24	8,773,161	44,654,868	2,634,563	5.08	16.9
	BLEWETT IC TURBINES	06-2024	30-R0.5 *	(7)	8,455,727.27	7,408,641	1,638,987	336,664	3.98	4.9
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	30-R0.5 *	(7)	22,476,731.53	9,641,480	14,408,622	9,767,204	43.45	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	30-R0.5 *	(7)	39,502,461.61	(379,217)	42,646,851	2,901,267	7.34	14.7
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	30-R0.5 *	(4)	121,712,253.32	48,127,557	78,453,186	4,737,903	3.89	16.6
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	30-R0.5 *	(4)	61,526,436.54	14,386,219	49,601,275	2,326,209	3.78	21.3
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	30-R0.5 *	(2)	230,437,633.01	(28,820,222)	263,866,608	14,883,340	6.46	17.7
	SUTTON BLACKSTART	06-2057	30-R0.5 *	(9)	65,019,558.96	1,224,776	69,646,543	2,651,182	4.08	26.3
	WEATHERSPOON IC TURBINES	06-2024	30-R0.5 *	(21)	12,638,464.88	14,847,046	445,496	86,525	0.68	5.1
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	30-R0.5 *	(4)	114,272,116.59	(21,766,797)	140,609,798	8,046,676	7.04	17.5
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	30-R0.5 *	(8)	236,173,460.30	45,471,509	209,595,828	9,344,070	3.96	22.4
	SUTTON COMBINED CYCLE	06-2053	30-R0.5 *	(3)	361,361,292.77	12,434,111	359,768,021	15,105,488	4.18	23.8
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	30-R0.5 *	(6)	443,686,010.74	30,441,659	439,865,513	19,052,498	4.29	23.1
	TOTAL PRIME MOVERS				1,769,134,020.76	141,789,923	1,715,201,596	91,873,589	5.19	18.7
343.10	PRIME MOVERS - ROTABLE PARTS									
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	6-L0.5 *	40	39,318,264.60	3,453,628	20,137,331	4,840,705	12.31	4.2
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	6-L0.5 *	40	44,987,832.65	7,894,446	19,098,254	5,974,679	13.28	3.2
	SUTTON COMBINED CYCLE	06-2053	6-L0.5 *	40	29,483,115.01	5,468,284	12,221,585	3,577,906	12.14	3.4
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	6-L0.5 *	40	56,542,095.59	6,820,315	27,104,942	7,057,740	12.48	3.8
	TOTAL PRIME MOVERS - ROTABLE PARTS				170,331,307.85	23,636,673	78,562,112	21,451,030	12.59	3.7
344.00	GENERATORS									
	ASHEVILLE IC TURBINE	06-2039	50-R2 *	(3)	7,769,953.49	3,627,517	4,375,535	233,653	3.01	18.7
	BLEWETT IC TURBINES	06-2024	50-R2 *	(7)	1,988,284.95	2,204,189	(76,724)	0	-	-
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-R2 *	(7)	12,472,614.73	8,742,209	4,603,489	3,097,560	24.83	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-R2 *	(7)	17,131,838.45	5,675,300	12,655,767	735,468	4.29	17.2
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-R2 *	(4)	22,068,501.33	10,644,166	12,307,075	632,402	2.87	19.5
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-R2 *	(4)	13,021,303.33	2,807,071	10,735,084	390,823	3.00	27.5
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-R2 *	(2)	37,046,160.65	(38,773,572)	76,560,656	3,735,595	10.08	20.5
	SUTTON BLACKSTART	06-2057	50-R2 *	(9)	2,145,710.72	274,377	2,064,447	59,357	2.77	34.8
	WEATHERSPOON IC TURBINES	06-2024	50-R2 *	(21)	2,095,743.68	2,565,954	(30,104)	0	-	-
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-R2 *	(4)	40,449,074.75	62,933,029	(20,865,991)	0	-	-
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-R2 *	(8)	31,516,637.44	6,327,771	27,710,198	946,600	3.00	29.3
	SUTTON COMBINED CYCLE	06-2053	50-R2 *	(3)	44,450,493.34	4,229,533	41,554,475	1,335,598	3.00	31.1
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-R2 *	(6)	55,122,184.33	5,647,199	52,782,316	1,748,825	3.17	30.2
	TOTAL GENERATORS				287,278,501.19	76,904,743	224,376,223	12,915,881	4.50	17.4
344.20	GENERATORS - SOLAR									
	CAMP LEJUNE	06-2040	25-S2.5 *	(9)	15,956,191.94	1,973,252	15,418,997	822,344	5.15	18.8
	FAYETTEVILLE	06-2040	25-S2.5 *	(11)	32,469,234.56	4,022,825	32,018,026	1,708,709	5.26	18.7
	ELM CITY	06-2041	25-S2.5 *	(15)	51,863,631.58	5,776,472	53,866,704	2,731,170	5.27	19.7
	WARSAW	06-2040	25-S2.5 *	(12)	87,181,902.80	10,880,666	86,763,065	4,629,736	5.31	18.7
	TOTAL GENERATORS - SOLAR				187,470,960.88	22,653,215	188,066,792	9,891,959	5.28	19.0
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	ASHEVILLE IC TURBINE	06-2039	50-R1.5 *	(3)	13,502,429.56	3,492,810	10,414,693	549,433	4.07	19.0
	BLEWETT IC TURBINES	06-2024	50-R1.5 *	(7)	1,418,891.29	1,450,318	67,896	12,494	0.88	5.4
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-R1.5 *	(7)	4,869,111.48	4,598,032	611,918	410,605	8.43	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-R1.5 *	(7)	10,782,807.93	4,167,477	7,370,127	433,757	4.02	17.0
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-R1.5 *	(4)	19,926,915.26	9,556,455	11,167,537	576,702	2.89	19.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-R1.5 *	(4)	10,599,164.94	2,350,198	8,672,934	321,295	3.03	27.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-R1.5 *	(2)	29,257,399.18	11,618,321	18,224,226	894,076	3.06	20.4
	SUTTON BLACKSTART	06-2057	50-R1.5 *	(9)	13,595,340.46	1,958,624	12,860,297	379,136	2.79	33.9
	WEATHERSPOON IC TURBINES	06-2024	50-R1.5 *	(21)	3,003,206.27	1,866,086	1,767,794	329,700	10.98	5.4
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-R1.5 *	(4)	21,653,205.44	7,093,541	15,425,793	723,937	3.34	21.3
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-R1.5 *	(8)	51,327,924.43	8,850,051	46,584,108	1,621,061	3.16	28.7
	SUTTON COMBINED CYCLE	06-2053	50-R1.5 *	(3)	62,940,670.78	3,515,905	61,312,986	2,012,729	3.20	30.5
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-R1.5 *	(6)	76,581,369.69	6,263,965	74,912,286	2,531,320	3.31	29.6
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				319,458,436.71	66,781,781	269,392,595	10,796,245	3.38	25.0
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR									
	CAMP LEJUNE	06-2040	25-S2.5 *	(9)	2,761,117.30	351,375	2,658,243	141,616	5.13	18.8
	FAYETTEVILLE	06-2040	25-S2.5 *	(11)	533,260.74	68,266	523,653	28,033	5.26	18.7
	ELM CITY	06-2041	25-S2.5 *	(15)	133,458.18	16,509	136,968	6,990	5.24	19.6
	WARSAW	06-2040	25-S2.5 *	(12)	1,258,878.46	163,411	1,246,533	66,731	5.30	18.7
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR				4,686,714.68	599,561	4,565,397	243,370	5.19	18.8

SPANOS Table 1 (As Filed)

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ASHEVILLE IC TURBINE	06-2039	30-S1 *	(3)	3,414,473.38	900,837	2,616,070	165,627	4.85	15.8
	BLEWETT IC TURBINES	06-2024	30-S1 *	(7)	204,914.55	80,191	139,068	26,575	12.97	5.2
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	30-S1 *	(7)	90,349.83	(168,029)	264,703	177,654	196.63	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	30-S1 *	(7)	1,432,545.23	806,305	726,518	44,312	3.09	16.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	30-S1 *	(4)	1,316,904.66	889,548	480,033	31,177	2.37	15.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	30-S1 *	(4)	1,125,769.23	408,002	762,798	38,046	3.38	20.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	30-S1 *	(2)	7,653,551.58	(2,805,709)	10,612,331	624,277	8.16	17.0
	SUTTON BLACKSTART	06-2057	30-S1 *	(9)	1,861,416.34	26,901	2,002,043	73,523	3.95	27.2
	WEATHERSPOON IC TURBINES	06-2024	30-S1 *	(21)	721,477.59	215,281	657,707	123,221	17.08	5.3
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	30-S1 *	(4)	4,901,411.09	4,552,021	545,446	26,262	0.54	20.8
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	30-S1 *	(8)	8,419,845.29	1,797,141	7,296,292	337,867	4.01	21.6
	SUTTON COMBINED CYCLE	06-2053	30-S1 *	(3)	8,363,725.23	630,158	7,984,479	335,284	4.01	23.8
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	30-S1 *	(6)	11,795,130.01	1,356,717	11,146,121	489,752	4.15	22.8
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				51,301,514.01	8,689,364	45,233,609	2,493,577	4.86	18.1
346.20	MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR									
	ELM CITY	06-2041	30-S2.5 *	(15)	10,069.36	467	11,112	528	5.24	21.0
	WARSAW	06-2040	30-S2.5 *	(12)	19,111.49	547	20,858	1,017	5.32	20.5
	TOTAL MISCELLANEOUS PLANT EQUIPMENT - SOLAR				29,180.85	1,015	31,970	1,545	5.29	20.7
	TOTAL OTHER PRODUCTION PLANT				**3,126,769,436.62**	**471,071,560**	**2,750,686,979**	**158,732,404**	**5.08**	**17.3**
	TOTAL PRODUCTION				**16,087,542,172.24**	**6,610,898,913**	**9,920,168,088**	**668,373,584**	**4.15**	**14.8**
	TRANSMISSION PLANT									
352.00	STRUCTURES AND IMPROVEMENTS		60-R3	(10)	90,193,203.79	30,731,591	68,480,933	1,622,028	1.80	42.2
353.00	STATION EQUIPMENT		55-R1.5	(15)	1,070,174,832.08	233,041,480	997,659,577	23,628,452	2.21	42.2
354.00	TOWERS AND FIXTURES		75-R4	(20)	78,936,364.53	46,268,549	48,455,088	936,307	1.19	51.8
355.00	POLES AND FIXTURES		49-R1.5	(40)	743,280,241.54	262,890,321	777,702,017	19,031,917	2.56	40.9
356.00	OVERHEAD CONDUCTORS AND DEVICES		65-R2.5	(40)	551,039,389.11	187,315,525	584,139,620	11,383,033	2.07	51.3
357.00	UNDERGROUND CONDUIT		60-R4	0	32,286.46	(584)	32,870	559	1.73	58.8
358.00	UNDERGROUND CONDUCTORS AND DEVICES		45-S2.5	0	21,603,999.00	1,688,307	19,915,692	504,195	2.33	39.5
359.00	ROADS AND TRAILS		75-R3	0	312,522.87	68,523	244,000	4,253	1.36	57.4
	TOTAL TRANSMISSION PLANT				**2,555,572,839.38**	**762,003,713**	**2,496,629,797**	**57,110,744**	**2.23**	**43.7**
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS		60-R2	(15)	127,079,158.04	48,130,054	98,010,977	2,021,366	1.59	48.5
362.00	STATION EQUIPMENT		48-R1	(15)	683,055,387.27	199,280,175	586,233,520	15,332,138	2.24	38.2
364.00	POLES, TOWERS AND FIXTURES		45-R2.5	(100)	855,785,431.01	618,419,612	1,093,151,250	33,556,194	3.92	32.6
365.00	OVERHEAD CONDUCTORS AND DEVICES		45-R1	(30)	1,208,423,459.24	617,880,131	953,070,366	24,922,045	2.06	38.2
366.00	UNDERGROUND CONDUIT		46-S2.5	(15)	199,779,066.87	72,884,435	156,861,492	4,725,775	2.37	33.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES		42-S2	(5)	1,134,635,170.25	622,088,309	569,278,619	18,411,036	1.62	30.9
368.00	LINE TRANSFORMERS		40-R2	(5)	1,131,254,323.64	379,239,615	808,577,425	27,806,592	2.46	29.1
369.00	SERVICES		55-R3	(20)	681,775,180.43	370,866,150	447,264,066	10,868,784	1.59	41.2
370.00	METERING EQUIPMENT		28-R4	(10)	51,889,323.64	28,415,375	28,662,881	1,063,840	2.05	26.9
370.01	METERS		28-R4	(5)	142,517,522.33	81,602,020	68,041,378	7,007,351	**	9.7
370.02	METERS - UOF		15-S2.5	0	69,710,613.08	2,407,594	67,303,019	4,645,856	6.66	14.5
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES		26-S0.5	(10)	318,551,648.97	252,936,350	97,470,464	4,405,748	1.38	22.1
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		25-R1	(10)	264,812,433.62	14,493,162	276,800,515	12,840,929	4.85	21.6
	TOTAL DISTRIBUTION PLANT				**6,869,268,718.39**	**3,308,642,984**	**5,250,725,972**	**167,607,654**	**2.44**	**31.3**

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	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
	GENERAL PLANT									
390.00	STRUCTURES AND IMPROVEMENTS		45-R1.5	(5)	156,446,136.21	31,155,047	133,113,396	3,805,402	2.43	35.0
391.00	OFFICE FURNITURE AND EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED		10,200,214.55	10,200,215	0	0	-	-
	AMORTIZED		15-SQ	0	14,520,609.30	2,860,000	11,660,609	968,950	6.67	12.0
	TOTAL OFFICE FURNITURE AND EQUIPMENT				24,720,823.85	13,060,215	11,660,609	968,950	3.92	12.0
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP		8-SQ	0	61,586,228.38	20,800,000	40,786,228	7,696,591	12.50	5.3
392.00	TRANSPORTATION EQUIPMENT		11-L2	15	69,975,818.26	34,325,441	25,154,004	4,493,909	6.42	5.6
393.00	STORES EQUIPMENT		20-SQ	0	2,059,932.97	822,000	1,237,933	102,894	5.00	12.0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		20-SQ	0	90,247,659.07	21,910,000	68,337,659	4,508,503	5.00	15.2
395.00	LABORATORY EQUIPMENT		15-SQ	0	6,739,788.51	3,908,000	2,831,789	449,309	6.67	6.3
396.00	POWER OPERATED EQUIPMENT		12-S6	0	5,679,686.30	2,225,815	3,453,872	412,343	7.26	8.4
397.00	COMMUNICATION EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED		59,435,956.41	59,435,956	0	0	-	-
	AMORTIZED		10-SQ	0	120,535,862.75	53,890,000	66,645,863	12,049,716	10.00	5.5
	TOTAL COMMUNICATION EQUIPMENT				179,971,819.16	113,325,956	66,645,863	12,049,716	6.70	5.5
398.00	MISCELLANEOUS EQUIPMENT		20-SQ	0	23,040,257.68	15,615,000	7,425,258	1,150,868	5.00	6.5
	TOTAL GENERAL PLANT				**620,468,150.39**	**257,147,474**	**360,646,611**	**35,638,485**	**5.74**	**10.1**
	TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT				**10,045,309,708.16**	**4,327,794,170**	**8,108,002,380**	**260,356,883**	**2.59**	**31.1**
	DEPRECIABLE LAND RIGHTS									
310.00	LAND RIGHTS									
	ASHEVILLE UNIT 1	12-2027	100-R4 *	0	919,201.95	1,049,268	(130,066)	0	-	-
	MAYO UNIT 1	06-2029	100-R4 *	0	3,577,117.54	3,213,884	363,233	34,725	0.97	10.50
	ROXBORO UNIT 1	06-2028	100-R4 *	0	1,827,202.76	1,910,729	(83,526)	0	-	-
	ROXBORO UNIT 3	06-2029	100-R4 *	0	3,037,934.25	3,151,250	(113,316)	0	-	-
	TOTAL ACCOUNT 310				9,361,456.50	9,325,132	36,325	34,725	0.37	-
320.00	LAND RIGHTS									
	HARRIS UNIT 1	10-2046	100-R4 *	0	49,809,293.03	33,296,139	16,513,154	601,134	1.21	27.5
	ROBINSON UNIT 2	07-2030	100-R4 *	0	315,919.74	316,714	(794)	0	-	-
	TOTAL LAND RIGHTS				50,125,212.77	33,612,853	16,512,360	601,134	1.20	27.5
320.10	RIGHTS OF WAY									
	BRUNSWICK UNIT 1	09-2036	100-R4 *	0	9,724.11	8,156	1,568	90	0.93	17.4
	BRUNSWICK UNIT 2	12-2034	100-R4 *	0	51,363.07	49,976	1,388	88	0.17	15.8
	ROBINSON UNIT 2	07-2030	100-R4 *	0	6,141.10	6,141	0	0	-	-
	TOTAL RIGHTS OF WAY				67,228.28	64,272	2,956	178	0.26	16.6
	TOTAL ACCOUNT 320				50,192,441.05	33,677,125	16,515,316	601,312	1.20	27.5
330.00	LAND RIGHTS									
	WALTERS	06-2034	110-R4 *	0	80,796.94	50,520	30,277	2,160	2.67	14.0
330.10	RIGHTS OF WAY									
	BLEWETT	06-2055	110-R4 *	0	9,598.14	6,297	3,301	195	2.03	16.9
	MARSHALL	06-2035	110-R4 *	0	3,728.53	2,548	1,180	98	2.63	12.0
	TILLERY	06-2055	110-R4 *	0	19,764.49	13,269	6,495	261	1.32	24.9
	WALTERS	06-2034	110-R4 *	0	33,333.15	20,634	12,699	887	2.66	14.3
	TOTAL RIGHTS OF WAY				66,424.31	42,748	23,675	1,441	2.17	16.4
	TOTAL ACCOUNT 330				147,221.25	93,268	53,952	3,601	2.45	15.0
340.00	LAND RIGHTS									
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	60-R4 *	0	2,048,655.08	1,037,253	1,011,402	49,114	2.40	20.6
340.10	RIGHTS OF WAY									
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	60-R4 *	0	2,532,367.27	1,106,468	1,425,899	67,739	2.67	21.0
	TOTAL ACCOUNT 340.1				4,581,022.35	2,143,721	2,437,301	116,853	2.55	20.9

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	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
350.10	RIGHTS OF WAY		75-R3	0	176,749,823.75	68,578,311	108,171,513	2,039,608	1.15	53.0
360.00	LAND RIGHTS		65-R3	0	107,521.37	19,073	88,448	1,586	1.48	55.8
360.10	RIGHTS OF WAY		65-R3	0	23,908,367.28	12,009,169	11,899,199	298,919	1.25	39.8
389.10	RIGHTS OF WAY		60-R3	0	51,783.33	(670,230)	722,014	27,147	52.42	26.6
	TOTAL DEPRECIABLE LAND RIGHTS				**265,099,636.88**	**125,175,569**	**139,924,068**	**3,123,751**	**1.18**	**44.8**
	TOTAL ELECTRIC PLANT				**26,397,951,517.28**	**11,063,868,652**	**18,168,094,536**	**931,854,218**	**3.53**	**19.5**
	RESERVE ADJUSTMENT FOR AMORTIZATION									
391.00	OFFICE FURNITURE AND EQUIPMENT					(17,130,482)		3,426,096 ***		
393.00	STORES EQUIPMENT					(762,086)		152,417 ***		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(11,388,283)		2,277,657 ***		
395.00	LABORATORY EQUIPMENT					398,322		(79,664) ***		
397.00	COMMUNICATION EQUIPMENT					(56,777,491)		11,355,498 ***		
398.00	MISCELLANEOUS EQUIPMENT					(6,986,450)		1,397,290 ***		
	RESERVE ADJUSTMENT FOR AMORTIZATION					**(92,646,470)**		**18,529,294**		
	TOTAL DEPRECIABLE ELECTRIC PLANT				**26,397,951,517.28**	**10,971,222,183**	**18,168,094,536**	**950,383,512**		
	NONDEPRECIABLE AND ACCOUNTS NOT STUDIED									
	NONDEPRECIABLE ACCOUNTS									
301.00	ORGANIZATION				717,237.36	134,172				
302.00	FRANCHISE				59,871,453.31	25,092,129				
303.00	SOFTWARE				466,781,699.76	297,605,023				
310.00	LAND				23,302,268.83					
311.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT				248,681.03					
317.00	ARO - STEAM				827,197,087.81	342,312,237				
320.00	LAND				18,165,996.67					
321.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				1,854,278.73					
326.00	ARO - NUCLEAR				876,137,782.45	234,148,758				
330.00	LAND				2,681,695.37					
331.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT				245,662.37					
337.00	ARO - HYDRO				1,734,119.29	108,750				
340.00	LAND				5,421,028.49					
341.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				105,999,098.00					
347.20	ARO - OTHER PRODUCTION - SOLAR				7,642,438.48					
350.00	LAND				14,066,210.40					
352.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				18,335,571.33					
360.00	LAND				51,479,536.91					
389.00	LAND				8,096,305.23					
390.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				10,359,698.41					
399.00	ARO - GENERAL				2,717,587.67	1,704,333				
	TOTAL NONDEPRECIABLE ACCOUNTS				2,503,055,437.90	901,105,401				
	RETIRED PLANTS									
	CAPE FEAR				(1,328.95)	(1,329)				
	ROBINSON ICT					349,120				
	ROXBORO ICT					(146,504)				
	TOTAL RETIRED PLANTS				(1,328.95)	201,287				

SPANOS Table 1 (As Filed)

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
MISCELLANEOUS									
UNSPECIFIED					(381,483)				
NON-UTILITY					11,814,219				
HARRIS ACCELERATED DEPRECIATION					404,563,441				
CPL DECOMM					96,199,655				
RATE DIFFERENCE					(35,009,966)				
ARO					1,512,496				
ARO CONTRA COR					(26,235,987)				
OTHER (NO ACCOUNT ON 1085 PROVIDED)					22,144				
TOTAL MISCELLANEOUS				0.00	452,484,518				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				**2,503,054,108.95**	**1,353,791,206**				
TOTAL PLANT				**28,901,005,626.23**	**12,325,013,388**				

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.
** Annual Accrual Amount calculated based on remaining amortization period of 9.71 years (March 2028 which is 10 years from implementation).
*** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting.

Accrual rates for the Asheville Combined Cycle Plant when placed in service by November 2019 will be as follows:

Account	Rate
341.00	2.87
342.00	2.93
343.00	3.78
343.10	10.68
344.00	2.85
345.00	2.93
346.00	3.63

Accrual rates for new Battery Storage Assets based on a 15-L3 survivor curve and 0% net salvage will be as follows:

Account	Rate
348.00	6.90
351.00	6.90
363.00	6.90

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	ASHEVILLE UNIT 1	12-2027	100-R2.5 *	(4)	42,616,358.21	39,177,778	5,143,234	573,609	1.35	9.0
	ASHEVILLE UNIT 2	12-2027	100-R2.5 *	(4)	42,579,071.25	31,072,574	13,209,660	1,473,445	3.46	9.0
	MAYO UNIT 1	06-2035	100-R2.5 *	(5)	170,239,859.39	126,127,393	52,624,459	3,201,648	2.87	16.4
	ROXBORO UNIT 1	06-2028	100-R2.5 *	(5)	17,139,904.05	14,127,970	3,868,930	408,845	2.39	9.5
	ROXBORO UNIT 2	06-2028	100-R2.5 *	(5)	5,512,432.01	3,928,468	1,859,586	196,628	3.57	9.5
	ROXBORO UNIT 3	06-2033	100-R2.5 *	(5)	37,367,402.39	35,337,975	3,897,798	269,700	1.00	14.5
	ROXBORO UNIT 4	06-2033	100-R2.5 *	(5)	19,539,071.49	9,595,015	10,921,010	757,467	5.37	14.4
	ROXBORO COMMON	06-2033	100-R2.5 *	(5)	193,990,592.95	49,894,500	153,795,623	10,643,749	7.59	14.4
	TOTAL STRUCTURES AND IMPROVEMENTS				528,984,691.74	309,261,673	245,320,299	17,525,091	3.31	10.3
312.00	BOILER PLANT EQUIPMENT									
	ASHEVILLE UNIT 1	12-2027	60-R1 *	(4)	149,655,719.36	93,325,565	62,316,384	7,121,696	4.76	8.8
	ASHEVILLE UNIT 2	12-2027	60-R1 *	(4)	145,625,344.87	110,436,602	41,013,757	4,682,918	3.22	8.8
	MAYO UNIT 1	06-2035	60-R1 *	(5)	832,479,002.87	354,948,282	519,154,671	32,199,350	6.06	16.1
	ROXBORO UNIT 1	06-2028	60-R1 *	(5)	212,902,505.83	87,482,059	136,065,572	14,793,592	6.95	9.2
	ROXBORO UNIT 2	06-2028	60-R1 *	(5)	309,506,429.33	168,229,667	156,752,084	17,017,838	5.50	9.2
	ROXBORO UNIT 3	06-2033	60-R1 *	(5)	333,830,832.31	118,836,753	231,685,621	16,421,917	6.87	14.1
	ROXBORO UNIT 4	06-2033	60-R1 *	(5)	404,141,708.49	275,790,947	148,557,847	10,465,956	3.61	14.2
	ROXBORO COMMON	06-2033	60-R1 *	(5)	320,174,907.77	168,313,679	167,869,974	11,810,431	5.13	14.2
	TOTAL BOILER PLANT EQUIPMENT				2,708,316,450.83	1,377,363,553	1,463,415,910	114,513,697	4.23	9.8
312.10	BOILER PLANT EQUIPMENT - SCR CATALYST									
	ASHEVILLE UNIT 1	12-2027	10-S1 *	0	3,957,262.78	4,500,630	(543,367)	0	-	
	ASHEVILLE UNIT 2	12-2027	10-S1 *	0	1,798,265.75	1,961,047	(162,782)	0	-	
	MAYO UNIT 1	06-2035	10-S1 *	0	7,428,602.62	7,594,648	(166,045)	0	-	
	ROXBORO UNIT 1	06-2028	10-S1 *	0	7,925,144.00	8,427,153	(502,009)	0	-	
	ROXBORO UNIT 2	06-2028	10-S1 *	0	5,857,261.54	6,103,037	(245,775)	0	-	
	ROXBORO UNIT 3	06-2033	10-S1 *	0	6,541,925.15	4,994,846	1,547,079	150,101	3.75	10.3
	ROXBORO UNIT 4	06-2033	10-S1 *	0	7,261,916.42	8,154,038	(892,122)	0	-	
	TOTAL BOILER PLANT EQUIPMENT - SCR CATALYST				40,770,378.26	41,735,399	(965,020)	150,101	0.37	(3.9)
314.00	TURBOGENERATOR UNITS									
	ASHEVILLE UNIT 1	12-2027	60-S0 *	(4)	18,830,227.72	7,586,897	11,996,540	1,378,245	7.32	8.7
	ASHEVILLE UNIT 2	12-2027	60-S0 *	(4)	13,968,640.50	13,145,255	1,382,131	155,826	1.12	8.9
	MAYO UNIT 1	06-2035	60-S0 *	(5)	109,608,959.00	65,409,412	49,679,995	3,107,202	4.44	16.0
	ROXBORO UNIT 1	06-2028	60-S0 *	(5)	45,628,567.76	18,857,340	29,052,656	3,153,178	6.91	9.2
	ROXBORO UNIT 2	06-2028	60-S0 *	(5)	44,959,643.18	15,793,614	31,414,011	3,418,913	7.60	9.2
	ROXBORO UNIT 3	06-2033	60-S0 *	(5)	73,030,422.44	30,051,305	46,630,638	3,299,417	6.30	14.1
	ROXBORO UNIT 4	06-2033	60-S0 *	(5)	69,565,691.07	35,567,696	37,476,280	2,664,378	5.35	14.1
	ROXBORO COMMON	06-2033	60-S0 *	(5)	458,890.76	337,291	144,545	10,310	3.14	14.0
	TOTAL TURBOGENERATOR UNITS				376,051,042.43	186,748,811	207,776,795	17,187,469	4.57	9.7
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	ASHEVILLE UNIT 1	12-2027	70-R1 *	(4)	17,304,563.70	10,105,982	7,890,765	896,804	5.18	8.8
	ASHEVILLE UNIT 2	12-2027	70-R1 *	(4)	10,774,312.04	11,377,112	(171,827)	0	-	
	MAYO UNIT 1	06-2035	70-R1 *	(5)	66,829,604.18	32,728,460	37,442,625	2,311,959	5.40	16.2
	ROXBORO UNIT 1	06-2028	70-R1 *	(5)	27,911,638.64	9,388,873	19,918,347	2,151,100	7.71	9.3
	ROXBORO UNIT 2	06-2028	70-R1 *	(5)	24,223,049.38	17,239,203	8,194,999	883,710	3.65	9.3
	ROXBORO UNIT 3	06-2033	70-R1 *	(5)	42,579,385.55	15,020,156	29,688,199	2,092,237	6.84	14.2
	ROXBORO UNIT 4	06-2033	70-R1 *	(5)	43,547,824.88	20,360,939	25,364,277	1,786,050	5.71	14.2
	ROXBORO COMMON	06-2033	70-R1 *	(5)	23,722,266.18	7,276,792	17,631,587	1,239,103	7.27	14.2
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				256,892,644.55	123,497,516	145,958,972	11,360,963	4.42	9.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ASHEVILLE UNIT 1	12-2027	45-S0 *	(4)	10,334,480.63	4,727,909	6,019,951	695,241	6.73	8.7
	ASHEVILLE UNIT 2	12-2027	45-S0 *	(4)	5,120,201.92	4,538,194	786,816	91,397	1.79	8.6
	MAYO UNIT 1	06-2035	45-S0 *	(5)	13,338,741.21	5,584,869	8,420,810	531,104	6.30	15.9
	ROXBORO UNIT 1	06-2028	45-S0 *	(5)	4,072,524.77	1,719,045	2,557,106	281,244	6.91	9.1
	ROXBORO UNIT 2	06-2028	45-S0 *	(5)	4,425,440.03	2,695,586	1,951,126	214,299	4.84	9.1
	ROXBORO UNIT 3	06-2033	45-S0 *	(5)	4,581,632.45	2,143,896	2,666,819	192,318	5.90	13.9
	ROXBORO UNIT 4	06-2033	45-S0 *	(5)	5,430,383.41	2,700,578	3,001,325	218,712	5.68	13.7
	ROXBORO COMMON	06-2033	45-S0 *	(5)	20,631,298.87	5,918,365	15,744,498	1,124,664	7.63	14.0
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT				67,934,703.29	30,028,440	41,148,451	3,348,979	4.93	9.6
	TOTAL STEAM PRODUCTION PLANT				**3,978,949,911.10**	**2,068,635,392**	**2,102,655,407**	**164,086,299**	**4.12**	**9.9**

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
	NUCLEAR PRODUCTION PLANT									
321.00	STRUCTURES AND IMPROVEMENTS									
	BRUNSWICK UNIT 1	09-2036	75-S1 *	(1)	423,009,418.66	182,352,007	244,887,506	14,175,485	3.35	17.3
	BRUNSWICK UNIT 2	12-2034	75-S1 *	(1)	397,968,469.79	223,090,544	178,857,611	11,520,013	2.89	15.5
	HARRIS UNIT 1	10-2046	75-S1 *	(2)	1,996,266,873.69	1,204,989,357	831,202,855	32,248,496	1.62	25.8
	HARRIS DISALLOWANCE	10-2046			(105,862,561.00)	(67,742,934)	(38,119,627)	(1,369,567)	1.29	27.8
	ROBINSON UNIT 2	07-2030	75-S1 *	(1)	373,649,660.90	190,668,370	186,717,788	16,338,445	4.37	11.4
	TOTAL STRUCTURES AND IMPROVEMENTS				3,085,031,862.04	1,733,357,343	1,403,546,132	72,912,872	2.36	19.2
322.00	REACTOR PLANT EQUIPMENT									
	BRUNSWICK UNIT 1	09-2036	52-R2 *	(1)	612,117,283.68	299,468,246	318,770,211	19,312,794	3.16	16.5
	BRUNSWICK UNIT 2	12-2034	52-R2 *	(1)	544,476,825.16	293,189,240	256,732,353	17,115,022	3.14	15.0
	HARRIS UNIT 1	10-2046	52-R2 *	(2)	1,075,559,612.15	425,966,772	671,104,032	28,850,918	2.68	23.3
	HARRIS DISALLOWANCE	10-2046			(132,409,445.00)	(84,730,657)	(47,678,788)	(1,713,010)	1.29	27.8
	ROBINSON UNIT 2	07-2030	52-R2 *	(1)	462,756,240.49	249,630,881	217,752,922	19,464,027	4.21	11.2
	TOTAL REACTOR PLANT EQUIPMENT				2,562,500,516.48	1,183,524,482	1,416,680,730	83,029,751	3.24	17.1
323.00	TURBOGENERATOR UNITS									
	BRUNSWICK UNIT 1	09-2036	40-S0 *	(1)	285,997,062.33	101,762,273	187,094,760	11,823,008	4.13	15.8
	BRUNSWICK UNIT 2	12-2034	40-S0 *	(1)	172,548,284.27	83,648,310	90,625,457	6,442,418	3.73	14.1
	HARRIS UNIT 1	10-2046	40-S0 *	(2)	535,687,360.49	148,284,568	398,116,540	17,371,808	3.24	22.9
	HARRIS DISALLOWANCE	10-2046			(610,466.00)	(390,646)	(219,820)	(7,898)	1.29	27.8
	ROBINSON UNIT 2	07-2030	40-S0 *	(1)	333,276,803.83	41,912,529	294,697,043	26,899,155	8.07	11.0
	TOTAL TURBOGENERATOR UNITS				1,326,899,044.92	375,217,034	970,313,979	62,528,491	4.71	15.5
324.00	ACCESSORY ELECTRIC EQUIPMENT									
	BRUNSWICK UNIT 1	09-2036	50-R2.5 *	(1)	161,647,774.74	48,960,985	114,303,267	6,821,086	4.22	16.8
	BRUNSWICK UNIT 2	12-2034	50-R2.5 *	(1)	210,342,927.28	83,854,412	128,591,944	8,431,189	4.01	15.3
	HARRIS UNIT 1	10-2046	50-R2.5 *	(2)	820,436,969.84	447,858,632	388,987,077	16,303,928	1.99	23.9
	HARRIS DISALLOWANCE	10-2046			(256,837,664.66)	(164,354,016)	(92,483,649)	(3,322,766)	1.29	27.8
	ROBINSON UNIT 2	07-2030	50-R2.5 *	(1)	279,070,966.07	77,699,673	204,162,003	17,942,656	6.43	11.4
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				1,214,660,973.27	494,019,687	743,560,643	46,176,093	3.80	16.1
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	BRUNSWICK UNIT 1	09-2036	50-R1.5 *	(1)	201,192,590.16	72,402,768	130,801,748	7,865,762	3.91	16.6
	BRUNSWICK UNIT 2	12-2034	50-R1.5 *	(1)	68,906,220.33	31,605,240	37,990,042	2,534,043	3.68	15.0
	HARRIS UNIT 1	10-2046	50-R1.5 *	(2)	247,301,101.58	110,487,995	141,759,129	5,889,127	2.38	24.1
	HARRIS DISALLOWANCE	10-2046			(55,577,154.00)	(35,564,599)	(20,012,555)	(719,014)	1.29	27.8
	ROBINSON UNIT 2	07-2030	50-R1.5 *	(1)	190,043,010.80	57,228,953	134,714,488	12,040,133	6.34	11.2
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				651,865,768.87	236,160,357	425,252,852	27,610,051	4.24	15.4
	TOTAL NUCLEAR PRODUCTION PLANT				**8,840,958,165.58**	**4,022,278,903**	**4,959,354,336**	**292,257,258**	**3.31**	**17.0**
	HYDRAULIC PRODUCTION PLANT									
331.00	STRUCTURES AND IMPROVEMENTS									
	BLEWETT	06-2055	110-R2 *	(33)	6,620,300.84	2,221,068	6,583,932	187,401	2.83	35.1
	MARSHALL	06-2035	110-R2 *	(16)	1,523,286.57	36,589	1,730,423	107,146	7.03	16.2
	TILLERY	06-2055	110-R2 *	(29)	6,634,057.32	1,449,284	7,108,649	202,328	3.05	35.1
	WALTERS	06-2034	110-R2 *	(6)	3,472,324.03	1,969,353	1,711,310	112,577	3.24	15.2
	TOTAL STRUCTURES AND IMPROVEMENTS				18,249,968.76	5,676,294	17,134,316	609,452	3.34	28.1
332.00	RESERVOIRS, DAMS AND WATERWAYS									
	BLEWETT	06-2055	120-R3 *	(33)	8,275,323.29	5,471,755	5,534,425	160,135	1.94	34.6
	MARSHALL	06-2035	120-R3 *	(16)	4,071,208.19	2,374,604	2,347,997	143,440	3.52	16.4
	TILLERY	06-2055	120-R3 *	(29)	6,796,645.31	4,942,178	3,825,494	110,074	1.62	34.8
	WALTERS	06-2034	120-R3 *	(6)	34,543,362.20	18,258,190	18,357,774	1,195,944	3.46	15.4
	TOTAL RESERVOIRS, DAMS AND WATERWAYS				53,686,538.99	31,046,729	30,065,689	1,609,593	3.00	18.7

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	BLEWETT	06-2055	75-R1.5 *	(33)	13,436,525.48	255,189	17,615,390	536,807	4.00	32.8
	MARSHALL	06-2035	75-R1.5 *	(16)	6,041,207.23	4,039,831	2,967,969	189,470	3.14	15.7
	TILLERY	06-2055	75-R1.5 *	(29)	14,142,264.87	1,061,347	17,182,175	530,595	3.75	32.4
	WALTERS	06-2034	75-R1.5 *	(6)	4,456,120.96	2,409,069	2,314,420	155,664	3.49	14.9
	TOTAL WATER WHEELS, TURBINES AND GENERATORS				38,076,118.54	7,765,436	40,079,954	1,412,536	3.71	28.4
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	BLEWETT	06-2055	55-R1 *	(33)	7,543,722.48	(213,543)	10,246,694	338,949	4.49	30.2
	MARSHALL	06-2035	55-R1 *	(16)	1,179,515.99	773,248	594,991	40,208	3.41	14.8
	TILLERY	06-2055	55-R1 *	(29)	3,853,242.31	944,048	4,026,634	137,612	3.57	29.3
	WALTERS	06-2034	55-R1 *	(6)	13,242,973.33	1,362,762	12,674,790	856,757	6.47	14.8
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				25,819,454.11	2,866,514	27,543,109	1,373,526	5.32	20.1
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	BLEWETT	06-2055	55-S0 *	(33)	1,826,329.58	422,693	2,006,325	66,903	3.66	30.0
	MARSHALL	06-2035	55-S0 *	(16)	200,696.66	66,551	166,257	10,921	5.44	15.2
	TILLERY	06-2055	55-S0 *	(29)	1,227,560.24	602,303	981,249	32,943	2.68	29.8
	WALTERS	06-2034	55-S0 *	(6)	1,756,787.00	448,826	1,413,368	96,765	5.51	14.6
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				5,011,373.48	1,540,374	4,567,200	207,532	4.14	22.0
336.00	ROADS, RAILROADS, AND BRIDGES									
	MARSHALL	06-2035	75-R3 *	(16)	12,946.58	9,238	5,780	364	2.81	15.9
	WALTERS	06-2034	75-R3 *	(6)	8,258.48	8,473	281	24	0.29	11.7
	TOTAL ROADS, RAILROADS, AND BRIDGES				21,205.06	17,711	6,061	388	1.83	15.6
	TOTAL HYDRAULIC PRODUCTION PLANT				**140,864,658.94**	**48,913,058**	**119,396,328**	**5,213,027**	**3.70**	**22.9**
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	ASHEVILLE IC TURBINE	06-2039	50-S1 *	(3)	31,762,836.46	15,086,579	17,629,142	975,677	3.07	18.1
	BLEWETT IC TURBINES	06-2024	50-S1 *	(7)	979,562.66	987,420	60,712	11,136	1.14	5.45
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-S1 *	(7)	362,282.66	1,161,265	(773,623)	0	-	
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-S1 *	(7)	8,403,245.66	7,799,625	1,191,848	69,646	0.83	17.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-S1 *	(4)	9,013,914.23	4,506,042	4,868,429	254,463	2.82	19.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-S1 *	(4)	1,356,819.84	323,439	1,087,654	40,347	2.97	27.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-S1 *	(2)	19,344,678.47	7,843,041	11,888,531	579,000	2.99	20.5
	SUTTON BLACKSTART	06-2057	50-S1 *	(9)	11,574,792.86	4,616,347	8,000,177	231,353	2.00	34.6
	WEATHERSPOON IC TURBINES	06-2024	50-S1 *	(21)	3,568,977.41	3,833,880	484,582	92,356	2.59	5.2
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-S1 *	(4)	47,694,242.52	40,526,455	9,075,557	440,153	0.92	20.6
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-S1 *	(8)	40,103,160.35	7,907,269	35,404,144	1,232,177	3.07	28.7
	SUTTON COMBINED CYCLE	06-2053	50-S1 *	(3)	13,462,878.60	(1,895,584)	15,762,349	512,673	3.81	30.7
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-S1 *	(6)	25,476,302.18	7,358,309	19,646,572	711,705	2.79	27.6
	TOTAL STRUCTURES AND IMPROVEMENTS				213,103,693.90	100,054,088	124,326,074	5,150,686	2.42	24.1
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR									
	CAMP LEJUNE	06-2040	30-S2.5 *	(9)	26,130.74	1,617	26,865	1,307	5.00	20.6
	FAYETTEVILLE	06-2040	30-S2.5 *	(11)	3,957.51	248	4,145	204	5.15	20.3
	ELM CITY	06-2041	30-S2.5 *	(15)	3,925.80	248	4,267	203	5.17	21.0
	TOTAL STRUCTURES AND IMPROVEMENTS - SOLAR				34,014.05	2,113	35,277	1,714	5.04	20.6
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
	ASHEVILLE IC TURBINE	06-2039	45-R2 *	(3)	5,115,723.34	2,495,453	2,773,742	148,602	2.90	18.7
	BLEWETT IC TURBINES	06-2024	45-R2 *	(7)	413,479.62	403,237	39,186	7,229	1.75	5.4
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	45-R2 *	(7)	5,048,367.44	5,817,173	(415,419)	0	-	
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	45-R2 *	(7)	7,243,963.20	5,872,288	1,878,753	108,699	1.50	17.3
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	45-R2 *	(4)	7,363,988.43	3,459,288	4,199,260	219,470	2.98	19.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	45-R2 *	(4)	1,461,178.80	360,131	1,159,495	43,476	2.98	26.7
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	45-R2 *	(2)	8,473,790.16	3,354,658	5,288,608	267,152	3.15	19.8
	SUTTON BLACKSTART	06-2057	45-R2 *	(9)	5,990,884.76	137,567	6,392,498	188,103	3.14	34.0
	WEATHERSPOON IC TURBINES	06-2024	45-R2 *	(21)	1,651,095.21	1,242,908	754,917	140,115	8.49	5.4
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	45-R2 *	(4)	13,523,522.65	5,631,253	8,433,211	405,772	3.00	20.8
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	45-R2 *	(8)	22,575,250.21	4,383,495	19,997,775	702,612	3.11	28.5
	SUTTON COMBINED CYCLE	06-2053	45-R2 *	(3)	19,656,537.55	(5,290,149)	25,536,382	835,790	4.25	30.6
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	45-R2 *	(6)	25,423,310.37	2,091,783	24,856,926	845,788	3.33	29.4
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES				123,941,091.74	29,959,084	100,895,334	3,912,808	3.16	25.8

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
343.00	PRIME MOVERS									
	ASHEVILLE IC TURBINE	06-2039	30-R0.5 *	(3)	51,871,873.24	8,773,161	44,654,868	2,634,563	5.08	16.9
	BLEWETT IC TURBINES	06-2024	30-R0.5 *	(7)	8,455,727.27	7,408,641	1,638,987	336,664	3.98	4.9
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	30-R0.5 *	(7)	22,476,731.53	9,641,480	14,408,622	9,767,204	43.45	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	30-R0.5 *	(7)	39,502,461.61	(379,217)	42,646,851	2,901,267	7.34	14.7
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	30-R0.5 *	(4)	121,712,253.32	48,127,557	78,453,186	4,737,903	3.89	16.6
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	30-R0.5 *	(4)	61,526,436.54	14,386,219	49,601,275	2,326,209	3.78	21.3
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	30-R0.5 *	(2)	230,437,633.01	(28,820,222)	263,866,608	14,883,340	6.46	17.7
	SUTTON BLACKSTART	06-2057	30-R0.5 *	(9)	65,019,558.96	1,224,776	69,646,543	2,651,182	4.08	26.3
	WEATHERSPOON IC TURBINES	06-2024	30-R0.5 *	(21)	12,638,464.88	14,847,046	445,496	86,525	0.68	5.1
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	30-R0.5 *	(4)	114,272,116.59	(21,766,797)	140,609,798	8,046,676	7.04	17.5
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	30-R0.5 *	(8)	236,173,460.30	45,471,509	209,595,828	9,344,070	3.96	22.4
	SUTTON COMBINED CYCLE	06-2053	30-R0.5 *	(3)	361,361,292.77	12,434,111	359,768,021	15,105,488	4.18	23.8
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	30-R0.5 *	(6)	443,686,010.74	30,441,659	439,865,513	19,052,498	4.29	23.1
	TOTAL PRIME MOVERS				1,769,134,020.76	141,789,923	1,715,201,597	91,873,589	5.19	18.7
343.10	PRIME MOVERS - ROTABLE PARTS									
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	6-L0.5 *	40	39,318,264.60	3,453,628	20,137,331	4,840,705	12.31	4.2
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	6-L0.5 *	40	44,987,832.65	7,894,446	19,098,254	5,974,679	13.28	3.2
	SUTTON COMBINED CYCLE	06-2053	6-L0.5 *	40	29,483,115.01	5,468,284	12,221,585	3,577,906	12.14	3.4
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	6-L0.5 *	40	56,542,095.59	6,820,315	27,104,942	7,057,740	12.48	3.8
	TOTAL PRIME MOVERS - ROTABLE PARTS				170,331,307.85	23,636,673	78,562,112	21,451,030	12.59	3.7
344.00	GENERATORS									
	ASHEVILLE IC TURBINE	06-2039	50-R2 *	(3)	7,769,953.49	3,627,517	4,375,535	233,653	3.01	18.7
	BLEWETT IC TURBINES	06-2024	50-R2 *	(7)	1,988,284.95	2,204,189	(76,724)	0	-	
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-R2 *	(7)	12,472,614.73	8,742,209	4,603,489	3,097,560	24.83	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-R2 *	(7)	17,131,838.45	5,675,300	12,655,767	735,468	4.29	17.2
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-R2 *	(4)	22,068,501.33	10,644,166	12,307,075	632,402	2.87	19.5
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-R2 *	(4)	13,021,303.33	2,807,071	10,735,084	390,823	3.00	27.5
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-R2 *	(2)	37,046,160.65	(38,773,572)	76,560,656	3,735,595	10.08	20.5
	SUTTON BLACKSTART	06-2057	50-R2 *	(9)	2,145,710.72	274,377	2,064,447	59,357	2.77	34.8
	WEATHERSPOON IC TURBINES	06-2024	50-R2 *	(21)	2,095,743.68	2,565,954	(30,104)	0	-	
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-R2 *	(4)	40,449,074.75	62,933,029	(20,865,991)	0	-	
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-R2 *	(8)	31,516,637.44	6,327,771	27,710,198	946,600	3.00	29.3
	SUTTON COMBINED CYCLE	06-2053	50-R2 *	(3)	44,450,493.34	4,229,533	41,554,475	1,335,598	3.00	31.1
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-R2 *	(6)	55,122,184.33	5,647,199	52,782,316	1,748,825	3.17	30.2
	TOTAL GENERATORS				287,278,501.19	76,904,743	224,376,224	12,915,881	4.50	17.4
344.20	GENERATORS - SOLAR									
	CAMP LEJUNE	06-2040	25-S2.5 *	(9)	15,956,191.94	1,973,252	15,418,997	822,344	5.15	18.8
	FAYETTEVILLE	06-2040	25-S2.5 *	(11)	32,469,234.56	4,022,825	32,018,026	1,708,709	5.26	18.7
	ELM CITY	06-2041	25-S2.5 *	(15)	51,863,631.58	5,776,472	53,866,704	2,731,170	5.27	19.7
	WARSAW	06-2040	25-S2.5 *	(12)	87,181,902.80	10,880,666	86,763,065	4,629,736	5.31	18.7
	TOTAL GENERATORS - SOLAR				187,470,960.88	22,653,215	188,066,792	9,891,959	5.28	19.0
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	ASHEVILLE IC TURBINE	06-2039	50-R1.5 *	(3)	13,502,429.56	3,492,810	10,414,693	549,433	4.07	19.0
	BLEWETT IC TURBINES	06-2024	50-R1.5 *	(7)	1,418,891.29	1,450,318	67,896	12,494	0.88	5.4
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-R1.5 *	(7)	4,869,111.48	4,598,032	611,918	410,605	8.43	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-R1.5 *	(7)	10,782,807.93	4,167,477	7,370,127	433,757	4.02	17.0
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-R1.5 *	(4)	19,926,915.26	9,556,455	11,167,537	576,702	2.89	19.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-R1.5 *	(4)	10,599,164.94	2,350,198	8,672,934	321,295	3.03	27.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-R1.5 *	(2)	29,257,399.18	11,618,321	18,224,226	894,076	3.06	20.4
	SUTTON BLACKSTART	06-2057	50-R1.5 *	(9)	13,595,340.46	1,958,624	12,860,297	379,136	2.79	33.9
	WEATHERSPOON IC TURBINES	06-2024	50-R1.5 *	(21)	3,003,206.27	1,866,086	1,767,794	329,700	10.98	5.4
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-R1.5 *	(4)	21,653,205.44	7,093,541	15,425,793	723,937	3.34	21.3
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-R1.5 *	(8)	51,327,924.43	8,850,051	46,584,108	1,621,061	3.16	28.7
	SUTTON COMBINED CYCLE	06-2053	50-R1.5 *	(3)	62,940,670.78	3,515,905	61,312,986	2,012,729	3.20	30.5
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-R1.5 *	(6)	76,581,369.69	6,263,965	74,912,286	2,531,320	3.31	29.6
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				319,458,436.71	66,781,781	269,392,595	10,796,245	3.38	25.0
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR									
	CAMP LEJUNE	06-2040	25-S2.5 *	(9)	2,761,117.30	351,375	2,658,243	141,616	5.13	18.8
	FAYETTEVILLE	06-2040	25-S2.5 *	(11)	533,260.74	68,266	523,653	28,033	5.26	18.7
	ELM CITY	06-2041	25-S2.5 *	(15)	133,458.18	16,509	136,968	6,990	5.24	19.6
	WARSAW	06-2040	25-S2.5 *	(12)	1,258,878.46	163,411	1,246,533	66,731	5.30	18.7
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR				4,686,714.68	599,561	4,565,397	243,370	5.19	18.8

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DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ASHEVILLE IC TURBINE	06-2039	30-S1 *	(3)	3,414,473.38	900,837	2,616,070	165,627	4.85	15.8
	BLEWETT IC TURBINES	06-2024	30-S1 *	(7)	204,914.55	80,191	139,068	26,575	12.97	5.2
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	30-S1 *	(7)	90,349.83	(168,029)	264,703	177,654	196.63	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	30-S1 *	(7)	1,432,545.23	806,305	726,518	44,312	3.09	16.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	30-S1 *	(4)	1,316,904.66	889,548	480,033	31,177	2.37	15.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	30-S1 *	(4)	1,125,769.23	408,002	762,798	38,046	3.38	20.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	30-S1 *	(2)	7,653,551.58	(2,805,709)	10,612,331	624,277	8.16	17.0
	SUTTON BLACKSTART	06-2057	30-S1 *	(9)	1,861,416.34	26,901	2,002,043	73,523	3.95	27.2
	WEATHERSPOON IC TURBINES	06-2024	30-S1 *	(21)	721,477.59	215,281	657,707	123,221	17.08	5.3
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	30-S1 *	(4)	4,901,411.09	4,552,021	545,446	26,262	0.54	20.8
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	30-S1 *	(8)	8,419,845.29	1,797,141	7,296,292	337,867	4.01	21.6
	SUTTON COMBINED CYCLE	06-2053	30-S1 *	(3)	8,363,725.23	630,158	7,984,479	335,284	4.01	23.8
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	30-S1 *	(6)	11,795,130.01	1,356,717	11,146,121	489,752	4.15	22.8
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				51,301,514.01	8,689,364	45,233,610	2,493,577	4.86	18.1
346.20	MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR									
	ELM CITY	06-2041	30-S2.5 *	(15)	10,069.36	467	11,112	528	5.24	21.0
	WARSAW	06-2040	30-S2.5 *	(12)	19,111.49	547	20,858	1,017	5.32	20.5
	TOTAL MISCELLANEOUS PLANT EQUIPMENT - SOLAR				29,180.85	1,015	31,970	1,545	5.29	20.7
	TOTAL OTHER PRODUCTION PLANT				**3,126,769,436.62**	**471,071,560**	**2,750,686,982**	**158,732,404**	**5.08**	**17.3**
	TOTAL PRODUCTION				**16,087,542,172.24**	**6,610,898,913**	**9,932,093,053**	**620,288,988**	**3.86**	**14.8**
	TRANSMISSION PLANT									
352.00	STRUCTURES AND IMPROVEMENTS		60-R3	(10)	90,193,203.79	30,731,591	68,480,933	1,622,028	1.80	42.2
353.00	STATION EQUIPMENT		55-R1.5	(15)	1,070,174,832.08	233,041,480	997,659,577	23,628,452	2.21	42.2
354.00	TOWERS AND FIXTURES		75-R4	(20)	78,936,364.53	46,268,549	48,455,088	936,307	1.19	51.8
355.00	POLES AND FIXTURES		49-R1.5	(40)	743,280,241.54	262,890,321	777,702,017	19,031,917	2.56	40.9
356.00	OVERHEAD CONDUCTORS AND DEVICES		65-R2.5	(40)	551,039,389.11	187,315,525	584,139,620	11,383,033	2.07	51.3
357.00	UNDERGROUND CONDUIT		60-R4	0	32,286.46	(584)	32,870	559	1.73	58.8
358.00	UNDERGROUND CONDUCTORS AND DEVICES		45-S2.5	0	21,603,999.00	1,688,307	19,915,692	504,195	2.33	39.5
359.00	ROADS AND TRAILS		75-R3	0	312,522.87	68,523	244,000	4,253	1.36	57.4
	TOTAL TRANSMISSION PLANT				**2,555,572,839.38**	**762,003,713**	**2,496,629,797**	**57,110,744**	**2.23**	**43.7**
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS		60-R2	(15)	127,079,158.04	48,130,054	98,010,977	2,021,366	1.59	48.5
362.00	STATION EQUIPMENT		48-R1	(15)	683,055,387.27	199,280,175	586,233,520	15,332,138	2.24	38.2
364.00	POLES, TOWERS AND FIXTURES		45-R2.5	(100)	855,785,431.01	618,419,612	1,093,151,250	33,556,194	3.92	32.6
365.00	OVERHEAD CONDUCTORS AND DEVICES		45-R1	(30)	1,208,423,459.24	617,880,131	953,070,366	24,922,045	2.06	38.2
366.00	UNDERGROUND CONDUIT		46-S2.5	(15)	199,779,066.87	72,884,435	156,861,492	4,725,775	2.37	33.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES		42-S2	(5)	1,134,635,170.25	622,088,309	569,278,619	18,411,036	1.62	30.9
368.00	LINE TRANSFORMERS		40-R2	(5)	1,131,254,323.64	379,239,615	808,577,425	27,806,592	2.46	29.1
369.00	SERVICES		55-R3	(20)	681,775,180.43	370,866,150	447,264,066	10,868,784	1.59	41.2
370.00	METERING EQUIPMENT		28-R4	(10)	51,889,323.64	28,415,375	28,662,881	1,063,840	2.05	26.9
370.01	METERS		28-R4	(5)	142,517,522.33	81,602,020	68,041,378	7,007,351	**	9.7
370.02	METERS - UOF		15-S2.5	0	69,710,613.08	2,407,594	67,303,019	4,645,856	6.66	14.5
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES		26-S0.5	(10)	318,551,648.97	252,936,350	97,470,464	4,405,748	1.38	22.1
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		25-R1	(10)	264,812,433.62	14,493,162	276,800,515	12,840,929	4.85	21.6
	TOTAL DISTRIBUTION PLANT				**6,869,268,718.39**	**3,308,642,984**	**5,250,725,972**	**167,607,654**	**2.44**	**31.3**

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
	GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		45-R1.5		(5)	156,446,136.21	31,155,047	133,113,396	3,805,402	2.43	35.0
391.00	OFFICE FURNITURE AND EQUIPMENT										
	FULLY ACCRUED		FULLY ACCRUED			10,200,214.55	10,200,215	0	0	-	
	AMORTIZED		15-SQ		0	14,520,609.30	2,860,000	11,660,609	968,950	6.67	12.0
	TOTAL OFFICE FURNITURE AND EQUIPMENT					24,720,823.85	13,060,215	11,660,609	968,950	3.92	12.0
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP		8-SQ		0	61,586,228.38	20,800,000	40,786,228	7,696,591	12.50	5.3
392.00	TRANSPORTATION EQUIPMENT		11-L2		15	69,975,818.26	34,325,441	25,154,004	4,493,909	6.42	5.6
393.00	STORES EQUIPMENT		20-SQ		0	2,059,932.97	822,000	1,237,933	102,894	5.00	12.0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		20-SQ		0	90,247,659.07	21,910,000	68,337,659	4,508,503	5.00	15.2
395.00	LABORATORY EQUIPMENT		15-SQ		0	6,739,788.51	3,908,000	2,831,789	449,309	6.67	6.3
396.00	POWER OPERATED EQUIPMENT		12-S6		0	5,679,686.30	2,225,815	3,453,872	412,343	7.26	8.4
397.00	COMMUNICATION EQUIPMENT										
	FULLY ACCRUED		FULLY ACCRUED			59,435,956.41	59,435,956	0	0	-	
	AMORTIZED		10-SQ		0	120,535,862.75	53,890,000	66,645,863	12,049,716	10.00	5.5
	TOTAL COMMUNICATION EQUIPMENT					179,971,819.16	113,325,956	66,645,863	12,049,716	6.70	5.5
398.00	MISCELLANEOUS EQUIPMENT		20-SQ		0	23,040,257.68	15,615,000	7,425,258	1,150,868	5.00	6.5
	TOTAL GENERAL PLANT					**620,468,150.39**	**257,147,474**	**360,646,611**	**35,638,485**	**5.74**	**10.1**
	TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT					**10,045,309,708.16**	**4,327,794,170**	**8,108,002,380**	**260,356,883**	**2.59**	**31.1**
	DEPRECIABLE LAND RIGHTS										
310.00	LAND RIGHTS										
	ASHEVILLE UNIT 1	12-2027	100-R4	*	0	919,201.95	1,049,268	(130,066)	0	-	
	MAYO UNIT 1	06-2035	100-R4	*	0	3,577,117.54	3,213,884	363,233	22,067	0.97	16.5
	ROXBORO UNIT 1	06-2028	100-R4	*	0	1,827,202.76	1,910,729	(83,526)	0	-	
	ROXBORO UNIT 3	06-2033	100-R4	*	0	3,037,934.25	3,151,250	(113,316)	0	-	
	TOTAL ACCOUNT 310					9,361,456.50	9,325,132	36,324	22,067	0.24	1.05
320.00	LAND RIGHTS										
	HARRIS UNIT 1	10-2046	100-R4	*	0	49,809,293.03	33,296,139	16,513,154	601,134	1.21	27.5
	ROBINSON UNIT 2	07-2030	100-R4	*	0	315,919.74	316,714	(794)	0	-	
	TOTAL LAND RIGHTS					50,125,212.77	33,612,853	16,512,360	601,134	1.20	27.5
320.10	RIGHTS OF WAY										
	BRUNSWICK UNIT 1	09-2036	100-R4	*	0	9,724.11	8,156	1,568	90	0.93	17.4
	BRUNSWICK UNIT 2	12-2034	100-R4	*	0	51,363.07	49,976	1,388	88	0.17	15.8
	ROBINSON UNIT 2	07-2030	100-R4	*	0	6,141.10	6,141	0	0	-	
	TOTAL RIGHTS OF WAY					67,228.28	64,272	2,956	178	0.26	16.6
	TOTAL ACCOUNT 320					50,192,441.05	33,677,125	16,515,316	601,312	1.20	27.5
330.00	LAND RIGHTS										
	WALTERS	06-2034	110-R4	*	0	80,796.94	50,520	30,277	2,160	2.67	14.0
330.10	RIGHTS OF WAY										
	BLEWETT	06-2055	110-R4	*	0	9,598.14	6,297	3,301	195	2.03	16.9
	MARSHALL	06-2035	110-R4	*	0	3,728.53	2,548	1,180	98	2.63	12.0
	TILLERY	06-2055	110-R4	*	0	19,764.49	13,269	6,495	261	1.32	24.9
	WALTERS	06-2034	110-R4	*	0	33,333.15	20,634	12,699	887	2.66	14.3
	TOTAL RIGHTS OF WAY					66,424.31	42,748	23,676	1,441	2.17	16.4
	TOTAL ACCOUNT 330					147,221.25	93,268	53,953	3,601	2.45	15.0
340.00	LAND RIGHTS										
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	60-R4	*	0	2,048,655.08	1,037,253	1,011,402	49,114	2.40	20.6
340.10	RIGHTS OF WAY										
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	60-R4	*	0	2,532,367.27	1,106,468	1,425,899	67,739	2.67	21.0
	TOTAL ACCOUNT 340.1					4,581,022.35	2,143,721	2,437,301	116,853	2.55	20.9

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
350.10	RIGHTS OF WAY		75-R3	0	176,749,823.75	68,578,311	108,171,513	2,039,608	1.15	53.0
360.00	LAND RIGHTS		65-R3	0	107,521.37	19,073	88,448	1,586	1.48	55.8
360.10	RIGHTS OF WAY		65-R3	0	23,908,367.28	12,009,169	11,899,199	298,919	1.25	39.8
389.10	RIGHTS OF WAY		60-R3	0	51,783.33	(670,230)	722,014	27,147	52.42	26.6
	TOTAL DEPRECIABLE LAND RIGHTS				**265,099,636.88**	**125,175,569**	**139,924,068**	**3,111,093**	**1.17**	**44.8**
	TOTAL ELECTRIC PLANT				**26,397,951,517.28**	**11,063,868,652**	**18,180,019,501**	**883,756,965**	**3.35**	**19.5**
	RESERVE ADJUSTMENT FOR AMORTIZATION									
391.00	OFFICE FURNITURE AND EQUIPMENT					(17,130,482)		3,426,096 ***		
393.00	STORES EQUIPMENT					(762,086)		152,417 ***		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(11,388,283)		2,277,657 ***		
395.00	LABORATORY EQUIPMENT					398,322		(79,664) ***		
397.00	COMMUNICATION EQUIPMENT					(56,777,491)		11,355,498 ***		
398.00	MISCELLANEOUS EQUIPMENT					(6,986,450)		1,397,290 ***		
	RESERVE ADJUSTMENT FOR AMORTIZATION					**(92,646,470)**		**18,529,294**		
	TOTAL DEPRECIABLE ELECTRIC PLANT				**26,397,951,517.28**	**10,971,222,183**	**18,180,019,501**	**902,286,259**		
	NONDEPRECIABLE AND ACCOUNTS NOT STUDIED									
	NONDEPRECIABLE ACCOUNTS									
301.00	ORGANIZATION				717,237.36	134,172				
302.00	FRANCHISE				59,871,453.31	25,092,129				
303.00	SOFTWARE				466,781,699.76	297,605,023				
310.00	LAND				23,302,268.83					
311.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT				248,681.03					
317.00	ARO - STEAM				827,197,087.81	342,312,237				
320.00	LAND				18,165,996.67					
321.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				1,854,278.73					
326.00	ARO - NUCLEAR				876,137,782.45	234,148,758				
330.00	LAND				2,681,695.37					
331.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT				245,662.37					
337.00	ARO - HYDRO				1,734,119.29	108,750				
340.00	LAND				5,421,028.49					
341.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				105,999,098.00					
347.20	ARO - OTHER PRODUCTION - SOLAR				7,642,438.48					
350.00	LAND				14,066,210.40					
352.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				18,335,571.33					
360.00	LAND				51,479,536.91					
389.00	LAND				8,096,305.23					
390.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				10,359,698.41					
399.00	ARO - GENERAL				2,717,587.67	1,704,333				
	TOTAL NONDEPRECIABLE ACCOUNTS				2,503,055,437.90	901,105,401				
	RETIRED PLANTS									
	CAPE FEAR				(1,328.95)	(1,329)				
	ROBINSON ICT					349,120				
	ROXBORO ICT					(146,504)				
	TOTAL RETIRED PLANTS				(1,328.95)	201,287				

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
MISCELLANEOUS									
UNSPECIFIED					(381,483)				
NON-UTILITY					11,814,219				
HARRIS ACCELERATED DEPRECIATION					404,563,441				
CPL DECOMM					96,199,655				
RATE DIFFERENCE					(35,009,966)				
ARO					1,512,496				
ARO CONTRA COR					(26,235,987)				
OTHER (NO ACCOUNT ON 1085 PROVIDED)					22,144				
TOTAL MISCELLANEOUS				0.00	452,484,518				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				**2,503,054,108.95**	**1,353,791,206**				
TOTAL PLANT				**28,901,005,626.23**	**12,325,013,388**				

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.

** Annual Accrual Amount calculated based on remaining amortization period of 9.71 years (March 2028 which is 10 years from implementation).

*** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting.

Accrual rates for the Asheville Combined Cycle Plant when placed in service by November 2019 will be as follows:

Account	Rate
341.00	2.87
342.00	2.93
343.00	3.78
343.10	10.68
344.00	2.85
345.00	2.93
346.00	3.63

Accrual rates for new Battery Storage Assets based on a 15-L3 survivor curve and 0% net salvage will be as follows:

Account	Rate
348.00	6.90
351.00	6.90
363.00	6.90

DOCKET NO. E-2, SUB 1219

Exhibit No. GDB-7

Impacts of Reducing Contingency on Dismantlement Costs from 20% to 10%

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
	STEAM PRODUCTION PLANT										
311.00	STRUCTURES AND IMPROVEMENTS										
	ASHEVILLE UNIT 1	12-2027	100-R2.5	*	(4)	42,616,358.21	39,177,778	5,143,234	573,609	1.35	9.0
	ASHEVILLE UNIT 2	12-2027	100-R2.5	*	(4)	42,579,071.25	31,072,574	13,209,660	1,473,445	3.46	9.0
	MAYO UNIT 1	06-2035	100-R2.5	*	(5)	170,239,859.39	126,127,393	52,624,459	3,201,648	2.87	16.4
	ROXBORO UNIT 1	06-2028	100-R2.5	*	(5)	17,139,904.05	14,127,970	3,868,930	408,845	2.39	9.5
	ROXBORO UNIT 2	06-2028	100-R2.5	*	(5)	5,512,432.01	3,928,468	1,859,586	196,628	3.57	9.5
	ROXBORO UNIT 3	06-2033	100-R2.5	*	(5)	37,367,402.39	35,337,975	3,897,798	269,700	1.00	14.5
	ROXBORO UNIT 4	06-2033	100-R2.5	*	(5)	19,539,071.49	9,595,015	10,921,010	757,467	5.37	14.4
	ROXBORO COMMON	06-2033	100-R2.5	*	(5)	193,990,592.95	49,894,500	153,795,623	10,643,749	7.59	14.4
	TOTAL STRUCTURES AND IMPROVEMENTS					528,984,691.74	309,261,673	245,320,299	17,525,091	3.31	
312.00	BOILER PLANT EQUIPMENT										
	ASHEVILLE UNIT 1	12-2027	60-R1	*	(4)	149,655,719.36	93,325,565	62,316,384	7,121,696	4.76	8.8
	ASHEVILLE UNIT 2	12-2027	60-R1	*	(4)	145,625,344.87	110,436,602	41,013,757	4,682,918	3.22	8.8
	MAYO UNIT 1	06-2035	60-R1	*	(5)	832,479,002.87	354,948,282	519,154,671	32,199,350	6.06	16.1
	ROXBORO UNIT 1	06-2028	60-R1	*	(5)	212,902,505.83	87,482,059	136,065,572	14,793,592	6.95	9.2
	ROXBORO UNIT 2	06-2028	60-R1	*	(5)	309,506,429.33	168,229,667	156,752,084	17,017,838	5.50	9.2
	ROXBORO UNIT 3	06-2033	60-R1	*	(5)	333,830,832.31	118,836,753	231,685,621	16,421,917	6.87	14.1
	ROXBORO UNIT 4	06-2033	60-R1	*	(5)	404,141,708.49	275,790,947	148,557,847	10,465,956	3.61	14.2
	ROXBORO COMMON	06-2033	60-R1	*	(5)	320,174,907.77	168,313,679	167,869,974	11,810,431	5.13	14.2
	TOTAL BOILER PLANT EQUIPMENT					2,708,316,450.83	1,377,363,553	1,463,415,910	114,513,697	4.23	
312.10	BOILER PLANT EQUIPMENT - SCR CATALYST										
	ASHEVILLE UNIT 1	12-2027	10-S1	*	0	3,957,262.78	4,500,630	(543,367)	0	-	0.0
	ASHEVILLE UNIT 2	12-2027	10-S1	*	0	1,798,265.75	1,961,047	(162,782)	0	-	0.0
	MAYO UNIT 1	06-2035	10-S1	*	0	7,428,602.62	7,594,648	(166,045)	0	-	0.0
	ROXBORO UNIT 1	06-2028	10-S1	*	0	7,925,144.00	8,427,153	(502,009)	0	-	0.0
	ROXBORO UNIT 2	06-2028	10-S1	*	0	5,857,261.54	6,103,037	(245,775)	0	-	0.0
	ROXBORO UNIT 3	06-2033	10-S1	*	0	6,541,925.15	4,994,846	1,547,079	150,101	3.75	10.3
	ROXBORO UNIT 4	06-2033	10-S1	*	0	7,261,916.42	8,154,038	(892,122)	0	-	0.0
	TOTAL BOILER PLANT EQUIPMENT - SCR CATALYST					40,770,378.26	41,735,399	(965,020)	150,101	0.37	
314.00	TURBOGENERATOR UNITS										
	ASHEVILLE UNIT 1	12-2027	60-S0	*	(4)	18,830,227.72	7,586,897	11,996,540	1,378,245	7.32	8.7
	ASHEVILLE UNIT 2	12-2027	60-S0	*	(4)	13,968,640.50	13,145,255	1,382,131	155,826	1.12	8.9
	MAYO UNIT 1	06-2035	60-S0	*	(5)	109,608,959.00	65,409,412	49,679,995	3,107,202	4.44	16.0
	ROXBORO UNIT 1	06-2028	60-S0	*	(5)	45,628,567.76	18,857,340	29,052,656	3,153,178	6.91	9.2
	ROXBORO UNIT 2	06-2028	60-S0	*	(5)	44,959,643.18	15,793,614	31,414,011	3,418,913	7.60	9.2
	ROXBORO UNIT 3	06-2033	60-S0	*	(5)	73,030,422.44	30,051,305	46,630,638	3,299,417	6.30	14.1
	ROXBORO UNIT 4	06-2033	60-S0	*	(5)	69,565,691.07	35,567,696	37,476,280	2,664,378	5.35	14.1
	ROXBORO COMMON	06-2033	60-S0	*	(5)	458,890.76	337,291	144,545	10,310	3.14	14.0
	TOTAL TURBOGENERATOR UNITS					376,051,042.43	186,748,811	207,776,795	17,187,469	4.57	
315.00	ACCESSORY ELECTRIC EQUIPMENT										
	ASHEVILLE UNIT 1	12-2027	70-R1	*	(4)	17,304,563.70	10,105,982	7,890,765	896,804	5.18	8.8
	ASHEVILLE UNIT 2	12-2027	70-R1	*	(4)	10,774,312.04	11,377,112	(171,827)	0	-	0.0
	MAYO UNIT 1	06-2035	70-R1	*	(5)	66,829,604.18	32,728,460	37,442,625	2,311,959	5.40	16.2
	ROXBORO UNIT 1	06-2028	70-R1	*	(5)	27,911,638.64	9,388,873	19,918,347	2,151,100	7.71	9.3
	ROXBORO UNIT 2	06-2028	70-R1	*	(5)	24,223,049.38	17,239,203	8,194,999	883,710	3.65	9.3
	ROXBORO UNIT 3	06-2033	70-R1	*	(5)	42,579,385.55	15,020,156	29,688,199	2,092,237	6.84	14.2
	ROXBORO UNIT 4	06-2033	70-R1	*	(5)	43,547,824.88	20,360,939	25,364,277	1,786,050	5.71	14.2
	ROXBORO COMMON	06-2033	70-R1	*	(5)	23,722,266.18	7,276,792	17,631,587	1,239,103	7.27	14.2
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					256,892,644.55	123,497,516	145,958,972	11,360,963	4.42	
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT										
	ASHEVILLE UNIT 1	12-2027	45-S0	*	(4)	10,334,480.63	4,727,909	6,019,951	695,241	6.73	8.7
	ASHEVILLE UNIT 2	12-2027	45-S0	*	(4)	5,120,201.92	4,538,194	786,816	91,397	1.79	8.6
	MAYO UNIT 1	06-2035	45-S0	*	(5)	13,338,741.21	5,584,869	8,420,810	531,104	6.30	15.9
	ROXBORO UNIT 1	06-2028	45-S0	*	(5)	4,072,524.77	1,719,045	2,557,106	281,244	6.91	9.1
	ROXBORO UNIT 2	06-2028	45-S0	*	(5)	4,425,440.03	2,695,586	1,951,126	214,299	4.84	9.1
	ROXBORO UNIT 3	06-2033	45-S0	*	(5)	4,581,632.45	2,143,896	2,666,819	192,318	5.90	13.9
	ROXBORO UNIT 4	06-2033	45-S0	*	(5)	5,430,383.41	2,700,578	3,001,325	218,712	5.68	13.7
	ROXBORO COMMON	06-2033	45-S0	*	(5)	20,631,298.87	5,918,365	15,744,498	1,124,664	7.63	14.0
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT					67,934,703.29	30,028,440	41,148,451	3,348,979	4.93	
	TOTAL STEAM PRODUCTION PLANT					**3,978,949,911.10**	**2,068,635,392**	**2,102,655,407**	**164,086,299**	**4.12**	

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)		NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
	NUCLEAR PRODUCTION PLANT										
321.00	STRUCTURES AND IMPROVEMENTS										
	BRUNSWICK UNIT 1	09-2036	75-S1	*	(1)	423,009,418.66	182,352,007	244,887,506	14,175,485	3.35	17.3
	BRUNSWICK UNIT 2	12-2034	75-S1	*	(1)	397,968,469.79	223,090,544	178,857,611	11,520,013	2.89	15.5
	HARRIS UNIT 1	10-2046	75-S1	*	(2)	1,996,266,873.69	1,204,989,357	831,202,855	32,248,496	1.62	25.8
	HARRIS DISALLOWANCE	10-2046				(105,862,561.00)	(67,742,934)	(38,119,627)	(1,369,567)	1.29	27.8
	ROBINSON UNIT 2	07-2030	75-S1	*	(1)	373,649,660.90	190,668,370	186,717,788	16,338,445	4.37	11.4
	TOTAL STRUCTURES AND IMPROVEMENTS					3,085,031,862.04	1,733,357,343	1,403,546,132	72,912,872	2.36	
322.00	REACTOR PLANT EQUIPMENT										
	BRUNSWICK UNIT 1	09-2036	52-R2	*	(1)	612,117,283.68	299,468,246	318,770,211	19,312,794	3.16	16.5
	BRUNSWICK UNIT 2	12-2034	52-R2	*	(1)	544,476,825.16	293,189,240	256,732,353	17,115,022	3.14	15.0
	HARRIS UNIT 1	10-2046	52-R2	*	(2)	1,075,559,612.15	425,966,772	671,104,032	28,850,918	2.68	23.3
	HARRIS DISALLOWANCE	10-2046				(132,409,445.00)	(84,730,657)	(47,678,788)	(1,713,010)	1.29	27.8
	ROBINSON UNIT 2	07-2030	52-R2	*	(1)	462,756,240.49	249,630,881	217,752,922	19,464,027	4.21	11.2
	TOTAL REACTOR PLANT EQUIPMENT					2,562,500,516.48	1,183,524,482	1,416,680,730	83,029,751	3.24	
323.00	TURBOGENERATOR UNITS										
	BRUNSWICK UNIT 1	09-2036	40-S0	*	(1)	285,997,062.33	101,762,273	187,094,760	11,823,008	4.13	15.8
	BRUNSWICK UNIT 2	12-2034	40-S0	*	(1)	172,548,284.27	83,648,310	90,625,457	6,442,418	3.73	14.1
	HARRIS UNIT 1	10-2046	40-S0	*	(2)	535,687,360.49	148,284,568	398,116,540	17,371,808	3.24	22.9
	HARRIS DISALLOWANCE	10-2046				(610,466.00)	(390,646)	(219,820)	(7,898)	1.29	27.8
	ROBINSON UNIT 2	07-2030	40-S0	*	(1)	333,276,803.83	41,912,529	294,697,043	26,899,155	8.07	11.0
	TOTAL TURBOGENERATOR UNITS					1,326,899,044.92	375,217,034	970,313,979	62,528,491	4.71	
324.00	ACCESSORY ELECTRIC EQUIPMENT										
	BRUNSWICK UNIT 1	09-2036	50-R2.5	*	(1)	161,647,774.74	48,960,985	114,303,267	6,821,086	4.22	16.8
	BRUNSWICK UNIT 2	12-2034	50-R2.5	*	(1)	210,342,927.28	83,854,412	128,591,944	8,431,189	4.01	15.3
	HARRIS UNIT 1	10-2046	50-R2.5	*	(2)	820,436,969.84	447,858,632	388,987,077	16,303,928	1.99	23.9
	HARRIS DISALLOWANCE	10-2046				(256,837,664.66)	(164,354,016)	(92,483,649)	(3,322,766)	1.29	27.8
	ROBINSON UNIT 2	07-2030	50-R2.5	*	(1)	279,070,966.07	77,699,673	204,162,003	17,942,656	6.43	11.4
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					1,214,660,973.27	494,019,687	743,560,643	46,176,093	3.80	
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT										
	BRUNSWICK UNIT 1	09-2036	50-R1.5	*	(1)	201,192,590.16	72,402,768	130,801,748	7,865,762	3.91	16.6
	BRUNSWICK UNIT 2	12-2034	50-R1.5	*	(1)	68,906,220.33	31,605,240	37,990,042	2,534,043	3.68	15.0
	HARRIS UNIT 1	10-2046	50-R1.5	*	(2)	247,301,101.58	110,487,995	141,759,129	5,889,127	2.38	24.1
	HARRIS DISALLOWANCE	10-2046				(55,577,154.00)	(35,564,599)	(20,012,555)	(719,014)	1.29	27.8
	ROBINSON UNIT 2	07-2030	50-R1.5	*	(1)	190,043,010.80	57,228,953	134,714,488	12,040,133	6.34	11.2
	TOTAL MISCELLANEOUS PLANT EQUIPMENT					651,865,768.87	236,160,357	425,252,852	27,610,051	4.24	
	TOTAL NUCLEAR PRODUCTION PLANT					**8,840,958,165.58**	**4,022,278,903**	**4,959,354,336**	**292,257,258**	**3.31**	
	HYDRAULIC PRODUCTION PLANT										
331.00	STRUCTURES AND IMPROVEMENTS										
	BLEWETT	06-2055	110-R2	*	(31)	6,620,300.84	2,221,068	6,451,526	183,632	2.83	35.1
	MARSHALL	06-2035	110-R2	*	(14)	1,523,286.57	36,589	1,699,957	105,260	7.03	16.2
	TILLERY	06-2055	110-R2	*	(26)	6,634,057.32	1,449,284	6,909,628	196,663	3.05	35.1
	WALTERS	06-2034	110-R2	*	(6)	3,472,324.03	1,969,353	1,711,310	112,577	3.24	15.2
	TOTAL STRUCTURES AND IMPROVEMENTS					18,249,968.76	5,676,294	16,772,422	598,132	3.28	
332.00	RESERVOIRS, DAMS AND WATERWAYS										
	BLEWETT	06-2055	120-R3	*	(31)	8,275,323.29	5,471,755	5,368,918	155,346	1.94	34.6
	MARSHALL	06-2035	120-R3	*	(14)	4,071,208.19	2,374,604	2,266,573	138,466	3.52	16.4
	TILLERY	06-2055	120-R3	*	(26)	6,796,645.31	4,942,178	3,621,595	104,207	1.62	34.8
	WALTERS	06-2034	120-R3	*	(6)	34,543,362.20	18,258,190	18,357,774	1,195,944	3.46	15.4
	TOTAL RESERVOIRS, DAMS AND WATERWAYS					53,686,538.99	31,046,729	29,614,859	1,593,963	2.97	

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	BLEWETT	06-2055	75-R1.5	* (31)	13,436,525.48	255,189	17,346,660	528,618	4.00	32.8
	MARSHALL	06-2035	75-R1.5	* (14)	6,041,207.23	4,039,831	2,847,145	181,757	3.14	15.7
	TILLERY	06-2055	75-R1.5	* (26)	14,142,264.87	1,061,347	16,757,907	517,493	3.75	32.4
	WALTERS	06-2034	75-R1.5	* (6)	4,456,120.96	2,409,069	2,314,420	155,664	3.49	14.9
	TOTAL WATER WHEELS, TURBINES AND GENERATORS				38,076,118.54	7,765,436	39,266,131	1,383,532	3.63	
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	BLEWETT	06-2055	55-R1	* (31)	7,543,722.48	(213,543)	10,095,820	333,958	4.49	30.2
	MARSHALL	06-2035	55-R1	* (14)	1,179,515.99	773,248	571,401	38,614	3.41	14.8
	TILLERY	06-2055	55-R1	* (26)	3,853,242.31	944,048	3,911,037	133,661	3.57	29.3
	WALTERS	06-2034	55-R1	* (6)	13,242,973.33	1,362,762	12,674,790	856,757	6.47	14.8
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				25,819,454.11	2,866,514	27,253,047	1,362,990	5.28	
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	BLEWETT	06-2055	55-S0	* (31)	1,826,329.58	422,693	1,969,799	65,685	3.66	30.0
	MARSHALL	06-2035	55-S0	* (14)	200,696.66	66,551	162,243	10,657	5.44	15.2
	TILLERY	06-2055	55-S0	* (26)	1,227,560.24	602,303	944,423	31,707	2.68	29.8
	WALTERS	06-2034	55-S0	* (6)	1,756,787.00	448,826	1,413,368	96,765	5.51	14.6
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				5,011,373.48	1,540,374	4,489,832	204,814	4.09	
336.00	ROADS, RAILROADS, AND BRIDGES									
	MARSHALL	06-2035	75-R3	* (14)	12,946.58	9,238	5,522	348	2.81	15.9
	WALTERS	06-2034	75-R3	* (6)	8,258.48	8,473	281	24	0.29	11.7
	TOTAL ROADS, RAILROADS, AND BRIDGES				21,205.06	17,711	5,802	372	1.75	
	TOTAL HYDRAULIC PRODUCTION PLANT				**140,864,658.94**	**48,913,058**	**117,402,094**	**5,143,803**	**3.65**	
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	ASHEVILLE IC TURBINE	06-2039	50-S1	* (3)	31,762,836.46	15,086,579	17,629,142	975,677	3.07	18.1
	BLEWETT IC TURBINES	06-2024	50-S1	* (6)	979,562.66	987,420	50,916	9,339	1.14	5.5
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-S1	* (6)	362,282.66	1,161,265	(777,246)	0	-	0.0
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-S1	* (6)	8,403,245.66	7,799,625	1,107,815	64,736	0.83	17.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-S1	* (4)	9,013,914.23	4,506,042	4,868,429	254,463	2.82	19.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-S1	* (4)	1,356,819.84	323,439	1,087,654	40,347	2.97	27.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-S1	* (2)	19,344,678.47	7,843,041	11,888,531	579,000	2.99	20.5
	SUTTON BLACKSTART	06-2057	50-S1	* (8)	11,574,792.86	4,616,347	7,884,430	228,006	2.00	34.6
	WEATHERSPOON IC TURBINES	06-2024	50-S1	* (18)	3,568,977.41	3,833,880	377,513	71,950	2.59	5.2
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-S1	* (3)	47,694,242.52	40,526,455	8,598,615	417,022	0.92	20.6
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-S1	* (7)	40,103,160.35	7,907,269	35,003,112	1,218,220	3.07	28.7
	SUTTON COMBINED CYCLE	06-2053	50-S1	* (3)	13,462,878.60	(1,895,584)	15,762,349	512,673	3.81	30.7
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-S1	* (5)	25,476,302.18	7,358,309	19,391,809	702,476	2.79	27.6
	TOTAL STRUCTURES AND IMPROVEMENTS				213,103,693.90	100,054,088	122,873,069	5,073,908	2.38	
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR									
	CAMP LEJUNE	06-2040	30-S2.5	* (8)	26,130.74	1,617	26,604	1,294	5.00	20.6
	FAYETTEVILLE	06-2040	30-S2.5	* (10)	3,957.51	248	4,105	202	5.15	20.3
	ELM CITY	06-2041	30-S2.5	* (13)	3,925.80	248	4,189	199	5.17	21.0
	TOTAL STRUCTURES AND IMPROVEMENTS - SOLAR				34,014.05	2,113	34,898	1,696	4.98	
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
	ASHEVILLE IC TURBINE	06-2039	45-R2	* (3)	5,115,723.34	2,495,453	2,773,742	148,602	2.90	18.7
	BLEWETT IC TURBINES	06-2024	45-R2	* (6)	413,479.62	403,237	35,052	6,466	1.75	5.4
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	45-R2	* (6)	5,048,367.44	5,817,173	(465,903)	0	-	0.0
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	45-R2	* (6)	7,243,963.20	5,872,288	1,806,313	104,508	1.50	17.3
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	45-R2	* (4)	7,363,988.43	3,459,288	4,199,260	219,470	2.98	19.1
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	45-R2	* (4)	1,461,178.80	360,131	1,159,495	43,476	2.98	26.7
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	45-R2	* (2)	8,473,790.16	3,354,658	5,288,608	267,152	3.15	19.8
	SUTTON BLACKSTART	06-2057	45-R2	* (8)	5,990,884.76	137,567	6,332,589	186,340	3.14	34.0
	WEATHERSPOON IC TURBINES	06-2024	45-R2	* (18)	1,651,095.21	1,242,908	705,384	130,921	8.49	5.4
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	45-R2	* (3)	13,523,522.65	5,631,253	8,297,976	399,265	3.00	20.8
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	45-R2	* (7)	22,575,250.21	4,383,495	19,772,022	694,680	3.11	28.5
	SUTTON COMBINED CYCLE	06-2053	45-R2	* (3)	19,656,537.55	(5,290,149)	25,536,382	835,790	4.25	30.6
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	45-R2	* (5)	25,423,310.37	2,091,783	24,602,693	837,137	3.33	29.4
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES				123,941,091.74	29,959,084	100,043,613	3,873,809	3.13	

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	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
343.00	PRIME MOVERS									
	ASHEVILLE IC TURBINE	06-2039	30-R0.5	* (3)	51,871,873.24	8,773,161	44,654,868	2,634,563	5.08	16.9
	BLEWETT IC TURBINES	06-2024	30-R0.5	* (6)	8,455,727.27	7,408,641	1,554,430	319,295	3.98	4.9
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	30-R0.5	* (6)	22,476,731.53	9,641,480	14,183,855	9,614,841	43.45	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	30-R0.5	* (6)	39,502,461.61	(379,217)	42,251,826	2,874,393	7.34	14.7
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	30-R0.5	* (4)	121,712,253.32	48,127,557	78,453,186	4,737,903	3.89	16.6
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	30-R0.5	* (4)	61,526,436.54	14,386,219	49,601,275	2,326,209	3.78	21.3
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	30-R0.5	* (2)	230,437,633.01	(28,820,222)	263,866,608	14,883,340	6.46	17.7
	SUTTON BLACKSTART	06-2057	30-R0.5	* (8)	65,019,558.96	1,224,776	68,996,348	2,626,432	4.08	26.3
	WEATHERSPOON IC TURBINES	06-2024	30-R0.5	* (18)	12,638,464.88	14,847,046	66,342	12,885	0.68	5.1
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	30-R0.5	* (3)	114,272,116.59	(21,766,797)	139,467,077	7,981,282	7.04	17.5
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	30-R0.5	* (7)	236,173,460.30	45,471,509	207,234,094	9,238,781	3.96	22.4
	SUTTON COMBINED CYCLE	06-2053	30-R0.5	* (3)	361,361,292.77	12,434,111	359,768,021	15,105,488	4.18	23.8
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	30-R0.5	* (5)	443,686,010.74	30,441,659	435,428,653	18,860,318	4.29	23.1
	TOTAL PRIME MOVERS				1,769,134,020.76	141,789,923	1,705,526,583	91,215,729	5.16	
343.10	PRIME MOVERS - ROTABLE PARTS									
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	6-L0.5	* 40	39,318,264.60	3,453,628	20,137,331	4,840,705	12.31	4.2
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	6-L0.5	* 40	44,987,832.65	7,894,446	19,098,254	5,974,679	13.28	3.2
	SUTTON COMBINED CYCLE	06-2053	6-L0.5	* 40	29,483,115.01	5,468,284	12,221,585	3,577,906	12.14	3.4
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	6-L0.5	* 40	56,542,095.59	6,820,315	27,104,942	7,057,740	12.48	3.8
	TOTAL PRIME MOVERS - ROTABLE PARTS				170,331,307.85	23,636,673	78,562,112	21,451,030	12.59	
344.00	GENERATORS									
	ASHEVILLE IC TURBINE	06-2039	50-R2	* (3)	7,769,953.49	3,627,517	4,375,535	233,653	3.01	18.7
	BLEWETT IC TURBINES	06-2024	50-R2	* (6)	1,988,284.95	2,204,189	(96,607)	0	-	0.0
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-R2	* (6)	12,472,614.73	8,742,209	4,478,763	3,013,635	24.83	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-R2	* (6)	17,131,838.45	5,675,300	12,484,449	725,512	4.29	17.2
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-R2	* (4)	22,068,501.33	10,644,166	12,307,075	632,402	2.87	19.5
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-R2	* (4)	13,021,303.33	2,807,071	10,735,084	390,823	3.00	27.5
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-R2	* (2)	37,046,160.65	(38,773,572)	76,560,656	3,735,595	10.08	20.5
	SUTTON BLACKSTART	06-2057	50-R2	* (8)	2,145,710.72	274,377	2,042,990	58,740	2.77	34.8
	WEATHERSPOON IC TURBINES	06-2024	50-R2	* (18)	2,095,743.68	2,565,954	(92,976)	0	-	0.0
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-R2	* (3)	40,449,074.75	62,933,029	(21,270,482)	0	-	0.0
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-R2	* (7)	31,516,637.44	6,327,771	27,395,031	935,834	3.00	29.3
	SUTTON COMBINED CYCLE	06-2053	50-R2	* (3)	44,450,493.34	4,229,533	41,554,475	1,335,598	3.00	31.1
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-R2	* (5)	55,122,184.33	5,647,199	52,231,094	1,730,561	3.17	30.2
	TOTAL GENERATORS				287,278,501.19	76,904,743	222,705,088	12,792,353	4.45	
344.20	GENERATORS - SOLAR									
	CAMP LEJUNE	06-2040	25-S2.5	* (8)	15,956,191.94	1,973,252	15,259,435	813,834	5.15	18.8
	FAYETTEVILLE	06-2040	25-S2.5	* (10)	32,469,234.56	4,022,825	31,693,333	1,691,381	5.26	18.7
	ELM CITY	06-2041	25-S2.5	* (13)	51,863,631.58	5,776,472	52,829,432	2,678,578	5.27	19.7
	WARSAW	06-2040	25-S2.5	* (10)	87,181,902.80	10,880,666	85,019,427	4,536,694	5.31	18.7
	TOTAL GENERATORS - SOLAR				187,470,960.88	22,653,215	184,801,627	9,720,487	5.19	
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	ASHEVILLE IC TURBINE	06-2039	50-R1.5	* (3)	13,502,429.56	3,492,810	10,414,693	549,433	4.07	19.0
	BLEWETT IC TURBINES	06-2024	50-R1.5	* (6)	1,418,891.29	1,450,318	53,707	9,883	0.88	5.4
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	50-R1.5	* (6)	4,869,111.48	4,598,032	563,226	377,932	8.43	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	50-R1.5	* (6)	10,782,807.93	4,167,477	7,262,299	427,411	4.02	17.0
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	50-R1.5	* (4)	19,926,915.26	9,556,455	11,167,537	576,702	2.89	19.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	50-R1.5	* (4)	10,599,164.94	2,350,198	8,672,934	321,295	3.03	27.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	50-R1.5	* (2)	29,257,399.18	11,618,321	18,224,226	894,076	3.06	20.4
	SUTTON BLACKSTART	06-2057	50-R1.5	* (8)	13,595,340.46	1,958,624	12,724,344	375,128	2.79	33.9
	WEATHERSPOON IC TURBINES	06-2024	50-R1.5	* (18)	3,003,206.27	1,866,086	1,677,698	312,897	10.98	5.4
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	50-R1.5	* (3)	21,653,205.44	7,093,541	15,209,261	713,775	3.34	21.3
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	50-R1.5	* (7)	51,327,924.43	8,850,051	46,070,828	1,603,200	3.16	28.7
	SUTTON COMBINED CYCLE	06-2053	50-R1.5	* (3)	62,940,670.78	3,515,905	61,312,986	2,012,729	3.20	30.5
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	50-R1.5	* (5)	76,581,369.69	6,263,965	74,146,473	2,505,443	3.31	29.6
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				319,458,436.71	66,781,781	267,500,212	10,679,903	3.34	
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR									
	CAMP LEJUNE	06-2040	25-S2.5	* (8)	2,761,117.30	351,375	2,630,632	140,145	5.13	18.8
	FAYETTEVILLE	06-2040	25-S2.5	* (10)	533,260.74	68,266	518,321	27,748	5.26	18.7
	ELM CITY	06-2041	25-S2.5	* (13)	133,458.18	16,509	134,298	6,854	5.24	19.6
	WARSAW	06-2040	25-S2.5	* (10)	1,258,878.46	163,411	1,221,355	65,383	5.30	18.7
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR				4,686,714.68	599,561	4,504,606	240,129	5.12	

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ASHEVILLE IC TURBINE	06-2039	30-S1	* (3)	3,414,473.38	900,837	2,616,070	165,627	4.85	15.8
	BLEWETT IC TURBINES	06-2024	30-S1	* (6)	204,914.55	80,191	137,018	26,183	12.97	5.2
	DARLINGTON IC TURBINE UNITS 1-11	06-2020	30-S1	* (6)	90,349.83	(168,029)	263,800	177,048	196.63	1.5
	DARLINGTON IC TURBINE UNITS 12 AND 13	06-2037	30-S1	* (6)	1,432,545.23	806,305	712,193	43,438	3.09	16.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	30-S1	* (4)	1,316,904.66	889,548	480,033	31,177	2.37	15.4
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	06-2049	30-S1	* (4)	1,125,769.23	408,002	762,798	38,046	3.38	20.0
	SMITH IC TURBINES (RICHMOND COUNTY)	06-2041	30-S1	* (2)	7,653,551.58	(2,805,709)	10,612,331	624,277	8.16	17.0
	SUTTON BLACKSTART	06-2057	30-S1	* (8)	1,861,416.34	26,901	1,983,428	72,839	3.95	27.2
	WEATHERSPOON IC TURBINES	06-2024	30-S1	* (18)	721,477.59	215,281	636,063	119,166	17.08	5.3
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	06-2042	30-S1	* (3)	4,901,411.09	4,552,021	496,432	23,902	0.54	20.8
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	06-2051	30-S1	* (7)	8,419,845.29	1,797,141	7,212,094	333,968	4.01	21.6
	SUTTON COMBINED CYCLE	06-2053	30-S1	* (3)	8,363,725.23	630,158	7,984,479	335,284	4.01	23.8
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	06-2052	30-S1	* (5)	11,795,130.01	1,356,717	11,028,170	484,569	4.15	22.8
	TOTAL MISCELLANEOUS PLANT EQUIPMENT				51,301,514.01	8,689,364	44,924,910	2,475,525	4.83	
346.20	MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR									
	ELM CITY	06-2041	30-S2.5	* (13)	10,069.36	467	10,911	518	5.24	21.0
	WARSAW	06-2040	30-S2.5	* (10)	19,111.49	547	20,475	998	5.32	20.5
	TOTAL MISCELLANEOUS PLANT EQUIPMENT - SOLAR				29,180.85	1,015	31,386	1,517	5.20	
	TOTAL OTHER PRODUCTION PLANT				**3,126,769,436.62**	**471,071,560**	**2,731,508,104**	**157,526,087**	**5.04**	
	TOTAL PRODUCTION				**16,087,542,172.24**	**6,610,898,913**	**9,910,919,941**	**619,013,448**	**3.85**	
	TRANSMISSION PLANT									
352.00	STRUCTURES AND IMPROVEMENTS		60-R3	(10)	90,193,203.79	30,731,591	68,480,933	1,622,028	1.80	42.2
353.00	STATION EQUIPMENT		55-R1.5	(15)	1,070,174,832.08	233,041,480	997,659,577	23,628,452	2.21	42.2
354.00	TOWERS AND FIXTURES		75-R4	(20)	78,936,364.53	46,268,549	48,455,088	936,307	1.19	51.8
355.00	POLES AND FIXTURES		49-R1.5	(40)	743,280,241.54	262,890,321	777,702,017	19,031,917	2.56	40.9
356.00	OVERHEAD CONDUCTORS AND DEVICES		65-R2.5	(40)	551,039,389.11	187,315,525	584,139,620	11,383,033	2.07	51.3
357.00	UNDERGROUND CONDUIT		60-R4	0	32,286.46	(584)	32,870	559	1.73	58.8
358.00	UNDERGROUND CONDUCTORS AND DEVICES		45-S2.5	0	21,603,999.00	1,688,307	19,915,692	504,195	2.33	39.5
359.00	ROADS AND TRAILS		75-R3	0	312,522.87	68,523	244,000	4,253	1.36	57.4
	TOTAL TRANSMISSION PLANT				**2,555,572,839.38**	**762,003,713**	**2,496,629,797**	**57,110,744**	**2.23**	**43.7**
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS		60-R2	(15)	127,079,158.04	48,130,054	98,010,977	2,021,366	1.59	48.5
362.00	STATION EQUIPMENT		48-R1	(15)	683,055,387.27	199,280,175	586,233,520	15,332,138	2.24	38.2
364.00	POLES, TOWERS AND FIXTURES		45-R2.5	(100)	855,785,431.01	618,419,612	1,093,151,250	33,556,194	3.92	32.6
365.00	OVERHEAD CONDUCTORS AND DEVICES		45-R1	(30)	1,208,423,459.24	617,880,131	953,070,366	24,922,045	2.06	38.2
366.00	UNDERGROUND CONDUIT		46-S2.5	(15)	199,779,066.87	72,884,435	156,861,492	4,725,775	2.37	33.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES		42-S2	(5)	1,134,635,170.25	622,088,309	569,278,619	18,411,036	1.62	30.9
368.00	LINE TRANSFORMERS		40-R2	(5)	1,131,254,323.64	379,239,615	808,577,425	27,806,592	2.46	29.1
369.00	SERVICES		55-R3	(20)	681,775,180.43	370,866,150	447,264,066	10,868,784	1.59	41.2
370.00	METERING EQUIPMENT		28-R4	(10)	51,889,323.64	28,415,375	28,662,881	1,063,840	2.05	26.9
370.01	METERS		28-R4	(5)	142,517,522.33	81,602,020	68,041,378	7,007,351	**	9.7
370.02	METERS - UOF		15-S2.5	0	69,710,613.08	2,407,594	67,303,019	4,645,856	6.66	14.5
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES		26-S0.5	(10)	318,551,648.97	252,936,350	97,470,464	4,405,748	1.38	22.1
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		25-R1	(10)	264,812,433.62	14,493,162	276,800,515	12,840,929	4.85	21.6
	TOTAL DISTRIBUTION PLANT				**6,869,268,718.39**	**3,308,642,984**	**5,250,725,972**	**167,607,654**	**2.44**	**31.3**

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
	GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		45-R1.5		(5)	156,446,136.21	31,155,047	133,113,396	3,805,402	2.43	35.0
391.00	OFFICE FURNITURE AND EQUIPMENT										
	FULLY ACCRUED		FULLY ACCRUED			10,200,214.55	10,200,215	0	0	-	
	AMORTIZED		15-SQ		0	14,520,609.30	2,860,000	11,660,609	968,950	6.67	12.0
	TOTAL OFFICE FURNITURE AND EQUIPMENT					24,720,823.85	13,060,215	11,660,609	968,950	3.92	12.0
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP		8-SQ		0	61,586,228.38	20,800,000	40,786,228	7,696,591	12.50	5.3
392.00	TRANSPORTATION EQUIPMENT		11-L2		15	69,975,818.26	34,325,441	25,154,004	4,493,909	6.42	5.6
393.00	STORES EQUIPMENT		20-SQ		0	2,059,932.97	822,000	1,237,933	102,894	5.00	12.0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		20-SQ		0	90,247,659.07	21,910,000	68,337,659	4,508,503	5.00	15.2
395.00	LABORATORY EQUIPMENT		15-SQ		0	6,739,788.51	3,908,000	2,831,789	449,309	6.67	6.3
396.00	POWER OPERATED EQUIPMENT		12-S6		0	5,679,686.30	2,225,815	3,453,872	412,343	7.26	8.4
397.00	COMMUNICATION EQUIPMENT										
	FULLY ACCRUED		FULLY ACCRUED			59,435,956.41	59,435,956	0	0	-	
	AMORTIZED		10-SQ		0	120,535,862.75	53,890,000	66,645,863	12,049,716	10.00	5.5
	TOTAL COMMUNICATION EQUIPMENT					179,971,819.16	113,325,956	66,645,863	12,049,716	6.70	5.5
398.00	MISCELLANEOUS EQUIPMENT		20-SQ		0	23,040,257.68	15,615,000	7,425,258	1,150,868	5.00	6.5
	TOTAL GENERAL PLANT					**620,468,150.39**	**257,147,474**	**360,646,611**	**35,638,485**	**5.74**	**10.1**
	TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT					**10,045,309,708.16**	**4,327,794,170**	**8,108,002,380**	**260,356,883**	**2.59**	**31.1**
	DEPRECIABLE LAND RIGHTS										
310.00	LAND RIGHTS										
	ASHEVILLE UNIT 1	12-2027	100-R4	*	0	919,201.95	1,049,268	(130,066)	0	-	
	MAYO UNIT 1	06-2035	100-R4	*	0	3,577,117.54	3,213,884	363,233	22,067	0.97	16.46
	ROXBORO UNIT 1	06-2028	100-R4	*	0	1,827,202.76	1,910,729	(83,526)	0	-	
	ROXBORO UNIT 3	06-2033	100-R4	*	0	3,037,934.25	3,151,250	(113,316)	0	-	
	TOTAL ACCOUNT 310					9,361,456.50	9,325,132	36,324	22,067	0.24	1.05
320.00	LAND RIGHTS										
	HARRIS UNIT 1	10-2046	100-R4	*	0	49,809,293.03	33,296,139	16,513,154	601,134	1.21	27.5
	ROBINSON UNIT 2	07-2030	100-R4	*	0	315,919.74	316,714	(794)	0	-	
	TOTAL LAND RIGHTS					50,125,212.77	33,612,853	16,512,360	601,134	1.20	27.5
320.10	RIGHTS OF WAY										
	BRUNSWICK UNIT 1	09-2036	100-R4	*	0	9,724.11	8,156	1,568	90	0.93	17.4
	BRUNSWICK UNIT 2	12-2034	100-R4	*	0	51,363.07	49,976	1,388	88	0.17	15.8
	ROBINSON UNIT 2	07-2030	100-R4	*	0	6,141.10	6,141	0	0	-	
	TOTAL RIGHTS OF WAY					67,228.28	64,272	2,956	178	0.26	16.6
	TOTAL ACCOUNT 320					50,192,441.05	33,677,125	16,515,316	601,312	1.20	27.5
330.00	LAND RIGHTS										
	WALTERS	06-2034	110-R4	*	0	80,796.94	50,520	30,277	2,160	2.67	14.0
330.10	RIGHTS OF WAY										
	BLEWETT	06-2055	110-R4	*	0	9,598.14	6,297	3,301	195	2.03	16.9
	MARSHALL	06-2035	110-R4	*	0	3,728.53	2,548	1,180	98	2.63	12.0
	TILLERY	06-2055	110-R4	*	0	19,764.49	13,269	6,495	261	1.32	24.9
	WALTERS	06-2034	110-R4	*	0	33,333.15	20,634	12,699	887	2.66	14.3
	TOTAL RIGHTS OF WAY					66,424.31	42,748	23,676	1,441	2.17	16.4
	TOTAL ACCOUNT 330					147,221.25	93,268	53,953	3,601	2.45	15.0
340.00	LAND RIGHTS										
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	60-R4	*	0	2,048,655.08	1,037,253	1,011,402	49,114	2.40	20.6
340.10	RIGHTS OF WAY										
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	06-2040	60-R4	*	0	2,532,367.27	1,106,468	1,425,899	67,739	2.67	21.0
	TOTAL ACCOUNT 340.1					4,581,022.35	2,143,721	2,437,301	116,853	2.55	20.9

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2018	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)
350.10	RIGHTS OF WAY		75-R3	0	176,749,823.75	68,578,311	108,171,513	2,039,608	1.15	53.0
360.00	LAND RIGHTS		65-R3	0	107,521.37	19,073	88,448	1,586	1.48	55.8
360.10	RIGHTS OF WAY		65-R3	0	23,908,367.28	12,009,169	11,899,199	298,919	1.25	39.8
389.10	RIGHTS OF WAY		60-R3	0	51,783.33	(670,230)	722,014	27,147	52.42	26.6
	TOTAL DEPRECIABLE LAND RIGHTS				**265,099,636.88**	**125,175,569**	**139,924,068**	**3,111,093**	**1.17**	**44.8**
	TOTAL ELECTRIC PLANT				**26,397,951,517.28**	**11,063,868,652**	**18,158,846,389**	**882,481,424**	**3.34**	**19.5**
	RESERVE ADJUSTMENT FOR AMORTIZATION									
391.00	OFFICE FURNITURE AND EQUIPMENT					(17,130,482)		3,426,096 ***		
393.00	STORES EQUIPMENT					(762,086)		152,417 ***		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(11,388,283)		2,277,657 ***		
395.00	LABORATORY EQUIPMENT					398,322		(79,664) ***		
397.00	COMMUNICATION EQUIPMENT					(56,777,491)		11,355,498 ***		
398.00	MISCELLANEOUS EQUIPMENT					(6,986,450)		1,397,290 ***		
	RESERVE ADJUSTMENT FOR AMORTIZATION					**(92,646,470)**		**18,529,294**		
	TOTAL DEPRECIABLE ELECTRIC PLANT				**26,397,951,517.28**	**10,971,222,183**	**18,158,846,389**	**901,010,718**		
	NONDEPRECIABLE AND ACCOUNTS NOT STUDIED									
	NONDEPRECIABLE ACCOUNTS									
301.00	ORGANIZATION				717,237.36	134,172				
302.00	FRANCHISE				59,871,453.31	25,092,129				
303.00	SOFTWARE				466,781,699.76	297,605,023				
310.00	LAND				23,302,268.83					
311.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT				248,681.03					
317.00	ARO - STEAM				827,197,087.81	342,312,237				
320.00	LAND				18,165,996.67					
321.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				1,854,278.73					
326.00	ARO - NUCLEAR				876,137,782.45	234,148,758				
330.00	LAND				2,681,695.37					
331.00	STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT				245,662.37					
337.00	ARO - HYDRO				1,734,119.29	108,750				
340.00	LAND				5,421,028.49					
341.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				105,999,098.00					
347.20	ARO - OTHER PRODUCTION - SOLAR				7,642,438.48					
350.00	LAND				14,066,210.40					
352.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				18,335,571.33					
360.00	LAND				51,479,536.91					
389.00	LAND				8,096,305.23					
390.00	STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE				10,359,698.41					
399.00	ARO - GENERAL				2,717,587.67	1,704,333				
	TOTAL NONDEPRECIABLE ACCOUNTS				2,503,055,437.90	901,105,401				
	RETIRED PLANTS									
	CAPE FEAR				(1,328.95)	(1,329)				
	ROBINSON ICT					349,120				
	ROXBORO ICT					(146,504)				
	TOTAL RETIRED PLANTS				(1,328.95)	201,287				

SPANOS TABLE 1 - Without Early Retirement of Mayo and Roxboro Unit 3 and Unit 4 and Utilizing 10% Contingency Rate for Dismantling Cost

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2018 (5)	BOOK RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)
MISCELLANEOUS									
UNSPECIFIED					(381,483)				
NON-UTILITY					11,814,219				
HARRIS ACCELERATED DEPRECIATION					404,563,441				
CPL DECOMM					96,199,655				
RATE DIFFERENCE					(35,009,966)				
ARO					1,512,496				
ARO CONTRA COR					(26,235,987)				
OTHER (NO ACCOUNT ON 1085 PROVIDED)					22,144				
TOTAL MISCELLANEOUS				0.00	452,484,518				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				**2,503,054,108.95**	**1,353,791,206**				
TOTAL PLANT				**28,901,005,626.23**	**12,325,013,388**				

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.

** Annual Accrual Amount calculated based on remaining amortization period of 9.71 years (March 2028 which is 10 years from implementation).

*** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting.

Accrual rates for the Asheville Combined Cycle Plant when placed in service by November 2019 will be as follows:

Account	Rate
341.00	2.87
342.00	2.93
343.00	3.78
343.10	10.68
344.00	2.85
345.00	2.93
346.00	3.63

Accrual rates for new Battery Storage Assets based on a 15-L3 survivor curve and 0% net salvage will be as follows:

Account	Rate
348.00	6.90
351.00	6.90
363.00	6.90

DIRECT TESTIMONY OF GARY D. BRUNAULT ON BEHALF OF FAYETTEVILLE PWC
DOCKET NO. E-2, SUB 1219

SPANOS TABLE 2 - As Filed, As Adjusted

DUKE ENERGY PROGRESS

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT

		As Filed					As Adjusted				
		TERMINAL RETIREMENTS		INTERIM RETIREMENTS		WEIGHTED	TERMINAL RETIREMENTS		INTERIM RETIREMENTS		WEIGHTED
Line No.	ACCOUNT	RETIREMENTS (%)	NET SALVAGE (%)	RETIREMENTS (%)	NET SALVAGE (%)	AVERAGE NET SALVAGE %	RETIREMENTS (%)	NET SALVAGE (%)	RETIREMENTS (%)	NET SALVAGE (%)	AVERAGE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(3)+(4)*(5)	(12)	(13)	(14)	(15)	(16)=(12)*(13)+(14)*(15)
1	**STEAM PRODUCTION**										
2	ASHEVILLE	99.42	(4)	0.58	(15)	(4)	99.42	(4)	0.58	(15)	(4)
3	MAYO	92.97	(4)	7.03	(15)	(5)	92.97	(4)	7.03	(15)	(5)
4	ROXBORO	93.61	(4)	6.39	(15)	(5)	93.61	(4)	6.39	(15)	(5)
5	**NUCLEAR PRODUCTION**										
6	BRUNSWICK	82.70	0	17.30	(7)	(1)	82.70	0	17.30	(7)	(1)
7	HARRIS	67.32	0	32.68	(7)	(2)	67.32	0	32.68	(7)	(2)
8	ROBINSON	91.73	0	8.27	(7)	(1)	91.73	0	8.27	(7)	(1)
9	**HYDRO PRODUCTION**										
10	BLEWETT	79.77	(37)	20.23	(18)	(33)	79.77	(34)	20.23	(18)	(31)
11	MARSHALL	91.61	(16)	8.39	(18)	(16)	91.61	(14)	8.39	(18)	(14)
12	TILLERY	77.20	(32)	22.80	(18)	(29)	77.20	(29)	22.80	(18)	(26)
13	WALTERS	93.99	(5)	6.01	(18)	(6)	93.99	(5)	6.01	(18)	(6)
14	**OTHER PRODUCTION**										
15	ASHEVILLE IC TURBINE	70.18	(2)	29.82	(4)	(3)	70.18	(2)	29.82	(4)	(3)
16	BLEWETT IC TURBINE	80.25	(8)	19.75	(4)	(7)	80.25	(7)	19.75	(4)	(6)
17	DARLINGTON IC TURBINE	79.44	(8)	20.56	(4)	(7)	79.44	(7)	20.56	(4)	(6)
18	H.F. LEE IC TURBINES (WAYNE COUNTY)	55.93	(5)	44.07	(4)	(5)	55.93	(4)	44.07	(4)	(4)
19	SMITH IC TURBINES (RICHMOND COUNTY)	63.70	(1)	36.30	(4)	(2)	63.70	(1)	36.30	(4)	(2)
20	SUTTON BLACKSTART	44.16	(14)	55.84	(4)	(8)	44.16	(14)	55.84	(4)	(8)
21	WEATHERSPOON IC TURBINE	76.04	(26)	23.96	(4)	(21)	76.04	(23)	23.96	(4)	(18)
22	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	62.37	(4)	37.63	(4)	(4)	62.37	(3)	37.63	(4)	(3)
23	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	48.16	(12)	51.84	(4)	(8)	48.16	(11)	51.84	(4)	(7)
24	SUTTON COMBINED CYCLE	44.66	(1)	55.34	(4)	(3)	44.66	(1)	55.34	(4)	(3)
25	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	44.46	(8)	55.54	(4)	(6)	44.46	(7)	55.54	(4)	(5)
26	**SOLAR PRODUCTION**										
27	CAMP LEJUNE	53.67	(16)	46.33	0	(9)	53.67	(14)	46.33	0	(8)
28	FAYETTEVILLE	53.45	(20)	46.55	0	(11)	53.45	(18)	46.55	0	(10)
29	ELM CITY	53.25	(28)	46.75	0	(15)	53.25	(25)	46.75	0	(13)
30	WARSAW	53.48	(22)	46.52	0	(12)	53.48	(19)	46.52	0	(10)

DIRECT TESTIMONY OF GARY D. BRUNAULT ON BEHALF OF FAYETTEVILLE PWC
DOCKET NO. E-2, SUB 1219

SPANOS TABLE 3 - As File, As Adjusted

DUKE ENERGY PROGRESS

TABLE 3. CALCULATION OF TERMINAL NET SALVAGE PERCENT

		As Filed					As Adjusted				
Line No.	UNIT	ESTIMATED RETIREMENT YEAR	TOTAL DECOMMISSIONING COSTS	ESCALATED TOTAL DECOMMISSIONING COSTS	TERMINAL RETIREMENTS	TOTAL NET SALVAGE	ESTIMATED RETIREMENT YEAR	TOTAL DECOMMISSIONING COSTS	ESCALATED TOTAL DECOMMISSIONING COSTS	TERMINAL RETIREMENTS	TOTAL NET SALVAGE
	(1)	(2)	(3)	(4)	(5)	(6)	(12)	(13)	(14)	(15)	(16)
1	**STEAM PRODUCTION**										
2	ASHEVILLE	2020	17,671,000	18,565,594	(454,176,455)	(4)	2020	15,834,000	16,635,596	(454,176,455)	(4)
3	MAYO	2029	31,251,000	41,004,020	(1,108,674,592)	(4)	2035	28,158,000	42,845,727	(1,108,674,592)	(4)
4	ROXBORO	2029	65,216,000	85,569,043	(2,142,600,644)	(4)	2033	58,331,000	84,480,680	(2,142,600,644)	(4)
5	**TOTAL STEAM PRODUCTION**		**114,138,000**	**145,138,657**	**(3,705,451,692)**	**(4)**		**102,323,000**	**143,962,003**	**(3,705,451,692)**	**(4)**
6	**HYDRO PRODUCTION**										
7	BLEWETT	2055	4,433,000	11,053,015	(30,076,674)	(37)	2055	4,062,000	10,127,983	(30,076,674)	(34)
8	MARSHALL	2035	1,216,000	1,850,288	(11,935,721)	(16)	2035	1,111,000	1,690,518	(11,935,721)	(14)
9	TILLERY	2055	3,235,000	8,065,983	(25,207,175)	(32)	2055	2,959,000	7,377,819	(25,207,175)	(29)
10	WALTERS	2034	1,992,000	2,957,135	(54,025,151)	(5)	2034	1,776,000	2,636,482	(54,025,151)	(5)
11	**TOTAL HYDRO PRODUCTION**		**10,876,000**	**23,926,421**	**(121,244,720)**	**(20)**		**9,908,000**	**21,832,801**	**(121,244,720)**	**(18)**
12	**OTHER PRODUCTION**										
13	ASHEVILLE IC TURBINE	2039	1,092,000	1,834,103	(79,612,990)	(2)	2039	914,000	1,535,137	(79,612,990)	(2)
14	BLEWETT IC TURBINE	2024	734,000	851,215	(10,801,714)	(8)	2024	660,000	765,398	(10,801,714)	(7)
15	DARLINGTON IC TURBINE	2037	5,082,000	8,124,340	(103,132,000)	(8)	2037	4,360,000	6,970,115	(103,132,000)	(7)
16	H.F. LEE IC TURBINES (WAYNE COUNTY)	2049	3,441,000	7,398,173	(151,276,320)	(5)	2049	2,950,000	6,342,520	(151,276,320)	(4)
17	SMITH IC TURBINES (RICHMOND COUNTY)	2041	1,664,000	2,936,312	(211,611,488)	(1)	2041	1,331,000	2,348,697	(211,611,488)	(1)
18	SUTTON BLACKSTART	2057	2,400,000 *	6,286,979	(44,240,006)	(14)	2057	2,400,000 *	6,286,979	(44,240,006)	(14)
19	WEATHERSPOON IC TURBINE	2024	4,012,000	4,652,690	(18,006,324)	(26)	2024	3,618,000	4,195,771	(18,006,324)	(23)
20	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	2042	3,021,750	5,465,518	(151,237,177)	(4)	2042	2,666,750	4,823,420	(151,237,177)	(3)
21	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	2051	10,066,250	22,738,157	(187,894,437)	(12)	2051	8,883,250	20,065,936	(187,894,437)	(11)
22	SUTTON COMBINED CYCLE	2053	1,391,000	3,301,128	(227,845,835)	(1)	2053	574,000	1,362,220	(227,845,835)	(1)
23	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	2052	9,887,000	22,891,590	(283,676,907)	(8)	2052	8,737,000	20,228,970	(283,676,907)	(7)
24	**TOTAL OTHER PRODUCTION**		**42,791,000**	**86,480,205**	**(1,469,335,198)**	**(6)**		**37,094,000**	**74,925,162**	**(1,469,335,198)**	**(5)**
25	**SOLAR PRODUCTION**										
26	CAMP LEJUNE	2040	926,000	1,594,175	(10,059,469)	(16)	2040	820,000	1,411,688	(10,059,469)	(14)
27	FAYETTEVILLE	2040	2,026,000	3,487,904	(17,642,536)	(20)	2040	1,810,000	3,116,045	(17,642,536)	(18)
28	ELM CITY	2041	4,419,000	7,797,815	(27,697,501)	(28)	2041	3,917,000	6,911,980	(27,697,501)	(25)
29	WARSAW	2040	6,160,000	10,604,880	(47,311,027)	(22)	2040	5,244,000	9,027,921	(47,311,027)	(19)
30	**TOTAL SOLAR PRODUCTION**		**13,531,000**	**23,484,774**	**(102,710,533)**	**(23)**		**11,791,000**	**20,467,634**	**(102,710,533)**	**(20)**
31	**TOTAL PRODUCTION**		**181,336,000**	**279,030,057**	**(5,398,742,143)**	**(5)**		**161,116,000**	**261,187,600**	**(5,398,742,143)**	**(5)**

32 *Utilized Sutton IC Turbine decommissioning estimate of $2.4 million

DIRECT TESTIMONY OF GARY D. BRUNAULT ON BEHALF OF FAYETTEVILLE PWC
DOCKET NO. E-2, SUB 1219

CALCULATION OF CONTINGENCY COST ADJUSTMENT

Line No	Item	Reference	Direct	Indirect	Contingency	Credits	Total	Contingency Adjustment (Note B)	Adjusted Total	Adjustment Ratio	Table 3 Name
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Asheville Coal	Spanos - VIII-2	18,377,000	919,000	3,675,000	(5,300,000)	17,671,000	(1,837,000)	15,834,000	-90%	Asheville
2	Asheville CTs	Spanos - VIII-2	1,773,000	89,000	355,000	(1,125,000)	1,092,000	(178,000)	914,000	-84%	Asheville IC Turbine
3	Blewett Hydros	Spanos - VIII-2	3,716,000	186,000	743,000	(212,000)	4,433,000	(371,000)	4,062,000	-92%	BLEWETT
4	Blewett CTs	Spanos - VIII-2	746,000	37,000	149,000	(198,000)	734,000	(74,000)	660,000	-90%	Blewett IC Turbine
5	Camp Lejeune Solar	Spanos - VIII-2	1,066,000	53,000	213,000	(406,000)	926,000	(106,000)	820,000	-89%	CAMP LEJUNE
6	Darlington	Spanos - VIII-2	7,227,000	361,000	1,445,000	(3,951,000)	5,082,000	(722,000)	4,360,000	-86%	Darlington IC Turbine
7	Elm City Solar	Spanos - VIII-2	5,022,000	251,000	1,004,000	(1,858,000)	4,419,000	(502,000)	3,917,000	-89%	Elm City
8	Fayetteveille Solar	Spanos - VIII-2	2,162,000	108,000	432,000	(676,000)	2,026,000	(216,000)	1,810,000	-89%	FAYETTEVILLE
9	Lee	Spanos - VIII-2	11,494,000	575,000	2,299,000	(4,481,000)	9,887,000	(1,150,000)	8,737,000	-88%	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)
10	Marshall	Spanos - VIII-2	1,050,000	53,000	210,000	(97,000)	1,216,000	(105,000)	1,111,000	-91%	Marshall
11	Mayo	Spanos - VIII-2	30,936,000	1,547,000	6,187,000	(7,419,000)	31,251,000	(3,093,000)	28,158,000	-90%	Mayo
12	Roxboro	Spanos - VIII-2	68,843,000	3,442,000	13,769,000	(20,838,000)	65,216,000	(6,885,000)	58,331,000	-89%	Roxboro
13	Smith CC (Block 4)	Spanos - VIII-2	3,550,464	177,546	710,185	(1,416,445)	3,021,750	(355,000)	2,666,750	-88%	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)
14	Smith CC - (Block 5)	Spanos - VIII-2	11,827,536	591,454	2,365,815	(4,718,555)	10,066,250	(1,183,000)	8,883,250	-88%	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)
15	Smith CTs	Spanos - VIII-2	3,337,000	167,000	667,000	(2,507,000)	1,664,000	(333,000)	1,331,000	-80%	SMITH IC TURBINES (RICHMOND COUNTY)
16	Sutton - CC	Spanos - VIII-2	8,172,000	409,000	1,634,000	(8,824,000)	1,391,000	(817,000)	574,000	-41%	SUTTON COMBINED CYCLE
17	Tilery	Spanos - VIII-2	2,753,000	138,000	551,000	(207,000)	3,235,000	(276,000)	2,959,000	-91%	Tillery
18	Walters	Spanos - VIII-2	2,167,000	108,000	433,000	(716,000)	1,992,000	(216,000)	1,776,000	-89%	Walters
19	Warsaw Solar	Spanos - VIII-2	9,162,000	458,000	1,832,000	(5,292,000)	6,160,000	(916,000)	5,244,000	-85%	WARSAW
20	Wayne County	Spanos - VIII-2	4,904,000	245,000	981,000	(2,689,000)	3,441,000	(491,000)	2,950,000	-86%	H.F. LEE IC TURBINES (WAYNE COUNTY)
21	Weatherspoon	Spanos - VIII-2	3,935,000	197,000	787,000	(907,000)	4,012,000	(394,000)	3,618,000	-90%	WEATHERSPOON IC TURBINE
22	Total from Spanos VIII-2	Sum of lines 1:21	202,220,000	10,112,000	40,442,000	(73,838,000)	178,936,000	(20,220,000)	158,716,000	-89%	
23	Sutton - Blackstart (Note A)		2,400,000				2,400,000		2,400,000	0%	SUTTON BLACKSTART
24	Total All	Line 22 + line 23	204,620,000	10,112,000	40,442,000	(73,838,000)	181,336,000	(20,220,000)	161,116,000	-89%	
							As Filed		**As Adjusted**		

25 **NOTES**
26 A - DEP estimated Sutton IC Turbine decommissioning at $2.4 million.
27 B - Contingency cost adjustment is based on a 10% contingency on direct commissioning cost.

CERTIFICATE OF SERVICE

The undersigned attorney hereby certifies that a copy of the foregoing Direct Testimony of Gary D. Brunault for the Fayetteville Public Works Commission was served on all parties of record by either hand delivery, email, or depositing the same in the United States mail, postage prepaid.

This the 13th day of April, 2020.

By: /s/ *James P. West*
James P. West

STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

In the Matter of,)
Application of Duke Energy) DOCKET NO.
Carolinas, LLC For Adjustment of) E-7, SUB 1214
Rates and Charges Applicable to)
Electric Service in North Carolina)

- -

In the Matter of,)
Application of Duke Energy) DOCKET NO.
Progress, LLC For Adjustment of) E-2, SUB 1219
Rates and Charges Applicable to)
Electric Service in North Carolina)

- -

Videoconference Video Deposition of

STEVEN C. HART, PG

(Taken by Duke Energy Carolinas, LLC

and Duke Energy Progress, LLC)

Charlotte, North Carolina

April 28, 2020

Reported by: Andrea Nobrega
Court Reporter
Notary Public

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Videoconference Video Deposition of STEVEN C. HART, taken by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Charlotte, North Carolina, on the 28th day of April 2020 at 9:33 a.m., before Andrea L. Nobrega, Notary Public and Court reporter.

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P R O C E E D I N G S

THE VIDEOGRAPHER: This is the beginning of media number one in the videotaped deposition of Steven C. Hart, in the matter of application of Duke Energy Carolinas, LLC for adjustment of rates and charges applicable to electric service in North Carolina, Case Numbers E-7, SUB 1214 and E-2, SUB 1219.
Today's date is April 28, 2020 and the time on the monitor is 9:32 a.m. My name is Martin Nobrega, and I am the videographer. The court reporter is Andrea Nobrega. We are with Huseby Global Litigation. Appearances are noted for the record.
Would the notary please swear in the witness.
Whereupon, STEVEN C. HART, having been first duly sworn, was examined and testified as follows:
THE VIDEOGRAPHER: You may proceed.
EXAMINATION BY COUNSEL FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC
BY MR. MEHTA:
Q. Thank you. And good morning, Mr. Hart. Could you just identify yourself

for the record, please, sir.
A. Yes. My name is Steven with a V, C. Hart. H-a-r-t is my last name.
Q. And Mr. Hart, are you the same Steven Hart whose deposition was taken on I think March 2, 2020 in Docket Number E-7, SUB 1214, the DEC rate case?
A. I am.
Q. And did you also prepare supplemental testimony in the DEC rate case that was filed on March 4, 2020?
A. I did.
Q. And, Mr. Hart, prior to the deposition, a series of exhibits to be used in connection with this deposition were sent to you and just confirm for me, if you would, that Exhibit No. 2 in that bunch of deposition exhibits is your supplemental testimony in the DEC rate case?
A. Yes, I printed out a copy of Exhibit No. 2, and it is the supplemental testimony in DEC rate case.
Q. And would you also confirm to me that Exhibit No. 3 that was sent to you

prior to the deposition are the work papers that you prepared in connection with that supplemental testimony?
A. Yes, they are. Exhibit No. 3 is, yes.
Q. And did you also prepare at this time in the Duke Energy Progress rate case, docket Number E-2, SUB 1219 direct testimony that was filed on April 13, 2020?
A. Yes.
Q. And, Mr. Hart, would you confirm for me that Exhibit No.'s 4 and 5 together compromise that direct testimony, with Exhibit No. 4 being the public portion and Exhibit No. 5 being the confidential pages?
A. Yes, it is the testimony, minus the exhibits.
Q. Correct. There are a number of exhibits that were presented with your testimony and we may refer to some of them today or may not, but they are also a matter of record in the underlying dockets, either the DEC or DEP dockets,

correct?
A. Correct, yes. That's my understanding, yes.
Q. Finally, Mr. Hart, is Exhibit No. 6 the work papers that you prepared in connection with your Duke Energy Progress direct testimony?
A. Yes, the work papers regarding the cost reduction analysis, yes.
Q. Let's take a look first, Mr. Hart, at your Duke Energy Carolinas supplemental testimony, which is Exhibit No. 2.
And you can pull it out so that you have it in front of you.
A. Yes, I have it in front of me now.
Q. And you state on page 126, lines five through six, that there are two disallowances that you recommend, correct?
A. Yes, that's correct.
Q. And the first of those disallowances that you recommend, is the cost of alternate water supplies, correct?
A. Correct.
Q. And the second one, if I'm reading correctly, and this is lines seven through

nine, is an adjustment "for several points in time by estimating the inflation in cost between the time DEC knew or should have known to take further action to address groundwater contamination at the basin." Did I read correctly?
A. Yes.
Q. Mr. Hart, I'm no grammarian, but it seems to me that there may be a grammatical error in that phrase.
You are estimating the inflation between the time DEC knew or should have known and what other time?
A. That's right, yes, well, it should probably say and the time when it did take action or started to take action after the Dan River spill in 2014.
Q. Okay, so the two points in time were actually multiple earlier points in time. You were comparing those points in time to the time when it took action?
A. Yes, which is explained probably -- well, in more detail on page 129, yes.
Q. On page 129?

A. Right, between the time when DEC knew it had issues, and when it started planning for basin closures in 2014, line entry 12 on that page.
My apologies, I didn't include the second part of the -- plus the --
Q. Mr. Hart --
THE COURT REPORTER: I'm sorry?
BY MR. MEHTA:
Q. If you could keep your voice up because I'm having a little bit of trouble hearing you, that would be great.
A. Okay.
THE COURT REPORTER: I'm having a little trouble, too. Maybe slow down just a little bit because it seems to cut off a little, too.
BY MR. MEHTA:
Q. I'm going back to your testimony. You state on page 126 and carrying forward to page 127, that DEC should have initiated a systematic plan sooner, correct?
A. Yes.
Q. And you state that that plan

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should have included, first, conversion to dry ash handling, correct?
A. Correct, yes.
Q. Second, eliminating other waste streams going to the basin, is that right?
A. It says wastewater streams, but, yes, correct.
Q. Third, that plan should have included developing closure plans, correct?
A. Correct.
Q. And fourth, that that plan should have included evaluating methods to reduce the environmental impact while the basins were still operational, correct?
A. Correct.
Q. Each one of those things, one through four, would have cost money at the time you say they should have, correct?
A. Correct, yes, they would have.
Q. Who was supposed to pay for those things?
A. DEC should have paid for them.
Q. And is it your testimony that DEC would have been able to recover those

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costs from its customers through the rate recovery mechanisms provided for under North Carolina law?
A. Well, I think there is several factors involved. To the extent that they needed to recover them, I would say yes.
There are cases where DEC spends money and they have already have sufficient money to recover these costs which they can --
Q. Well, it's your understanding --
A. My understanding is that they have already recovered costs sufficiently that they don't need to ask for these funds or wouldn't have to ask for these funds.
THE COURT REPORTER: I am sorry, this is the court reporter. I did not hear the end part. It kind of cut off of your answer.
THE VIDEOGRAPHER: The last thing we have is already recovered costs.
BY MR. MEHTA:
Q. Is it your testimony, Mr. Hart, that if the costs have not already been recovered, they are recoverable or would

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have been recoverable at the time that as of the time that they were incurred?
A. Well, again, I'm not an expert on cost recovery, and in terms of when the utilities can recover costs, and whether it's in looking backwards or whether they have to anticipate those costs looking forward.
I just don't know, but my understanding is that at some level potentially they could recover the cost from the ratepayers at the time.
Q. Mr. Hart, as of these various earlier points in time that you are comparing the more or less present time to, there was no requirement imposed by the law that any of those things that we just discussed, beginning the process of converting facilities to dry ash handling, eliminating other wastewater streams, developing closure plans and evaluating the methods to reduce the environmental impact, there is no legal requirement that any of those occurred, was there?
A. I would say once you have a 2L

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standard, exceedance violation, you are required to assess and address the source of those 2L standard exceedances, and those could include any one of these.
Q. But it also could include none of them, could it not?
A. They have to take some action in accordance with the 2L rule to try to address the source of the contamination.
Q. But the 2L rules would not require any one of the actions that have you listed as being required to occur, would they?
A. I think the last one specifically to methods to reduce the environmental impact while those basins were still operational is a requirement of the 2L standard.
Q. Well, how about the other three?
A. Yeah, those could be part of that to reduce the environmental impact. I mean those are potential options to reduce the environmental impact.
I believe they had an obligation to reduce the environmental impact in

accordance with the 2L rule.
Q. Okay. But do the 2L rules require Duke Energy Carolinas at any of those earlier points in time to begin the process of converting facilities to dry ash handling?
A. No, not specifically, no.
Q. Did the 2L rules require at any of those earlier points in time eliminating other wastewater streams that were being placed into the basins?
A. Not specifically, no, but it is an alternative to reduce environmental impact of the basins to keep groundwater.
Q. I understand that it's a potential alternative. My question to you, Mr. Hart, is, did the 2L rules require eliminating other wastewater streams that were placed into the basins at any point in time?
A. And I answered your question, not specifically, no.
Q. Did the 2L rules require at any of those earlier points in time, developing basin closure plans?

A. Not specifically, no, but that would be a potential option to begin the process of reducing the environmental impact on the basins.
Q. I understand that, but my question to you, Mr. Hart, is, did those rules, the 2L rules, require at any of those earlier points in time, developing basin closure plans?
A. Again, I answered your question, not specifically, no.
Q. And going further down on page 127, and specifically at lines eight and nine, you indicate that Duke Energy Carolinas' past inaction has led to increased costs today, correct?
A. Yes.
Q. And then you have a series of bullet points starting at line ten, correct?
A. Correct.
Q. And the first of those bullet points is essentially you indicate that activities had to be accelerated, and that costs more today, correct?

A. Correct, yes, accelerated actions just by their very nature cost more than non-accelerated actions.
Q. You have not specifically quantified the amount of increased cost related to accelerated actions, have you?
A. Not specifically, no. That's why -- well --
Q. I'm sorry, Mr. Hart, you faded on me there. You have not specifically quantified the increased cost associated with accelerated activity, is that correct?
A. That's correct, and that's why the cost reduction I have in here is a minimum because that would have increased the cost reduction.
Q. But with respect to that specific item, the cost, increased cost associated with accelerated activities, you have not specifically quantified that cost as part of your testimony, have you?
A. Again, I answered your question not specifically, no, but I'm allowed to explain my answer further, which I did.

Q. Okay. I would like an answer to the question and you can explain all you want.
A. I have every time you have asked me.
Q. With respect to the second bullet, you have not specifically quantified the amount of increased cost associated with that second bullet, have you?
A. Not specifically, no.
Q. And with respect to the third bullet, you have not specifically quantified the amount of increased cost associated with what you state in that bullet, do you?
A. No, I have. That's what my time value of money analysis does.
Q. Well, your time value of money analysis is really the fourth bullet, which is on page 128, isn't it, Mr. Hart?
A. Well, it's more than one. The cost would have been less for its customers at the time than it is today because of inflation.
Q. That's the fourth bullet, correct?

A. Well, it's just -- I mean I think it's part of the third and fourth bullet. DEC taking action sooner --

Q. Well, the third bullet says, "most of the expenditures that DEC seeks to recover for coal ash basin closures and CCR disposal, were incurred at coal plants that are retired and have not been used for several years to produce power for ratepayers." Do you see that?

A. Yes.

Q. You have not specifically quantified the cost, the additional increased costs associated with your assertion that DEC seeks to recover for coal ash basin closures and CCR disposal that was incurred at coal plants that are retired and have not been used for several years to produce power, isn't that correct?

MS. TOWNSEND: Objection, asked and answered.

THE WITNESS: No, I don't think so. I mean the next sentence says had DEC taken action sooner, then the cost would

have been included in the cost of service for customers while the coal plants were in use.

Those costs would have been less because of inflation. That's the analysis that I did.

BY MR. MEHTA:

Q. Let's go on to the next bullet then on page 128, line four. You indicate that DEC's costs are higher today due to inflation, correct?

A. Correct.

Q. And this one I think we can all agree is one that you did attempt to quantify the amount of increased costs, correct?

MS. TOWNSEND: Objection as to form.

THE WITNESS: Yes, I did.

BY MR. MEHTA:

Q. And the sole method that you chose to attempt to quantify it is what you called the time value of money method, is that correct?

A. Yes -- I mean basically, yes.

Q. Now, Mr. Hart, you acknowledged during your prior deposition that in your original pre-filed testimony, you had not attempted to quantify the amount of additional cost, correct?

A. No, I don't think that's what I said.

Q. What do you think you said?

A. My recollection is that I said I had done some calculations, but we had decided not to include them in the testimony at that time.

Q. All right. So in your pre-filed testimony, there was no calculation of original pre-filed testimony? There was no calculation of any additional cost, correct?

MS. TOWNSEND: Objection as to form.

THE WITNESS: I did not include a specific amount, arrange a specific amount in the original pre-filed testimony.

That's why the supplemental testimony we are talking about here was filed.

THE VIDEOGRAPHER: Can you repeat that, please?

THE COURT REPORTER: The end of your answer.

THE WITNESS: There is specific costs, or range in cost was not included in my original pre-filed testimony and that's why the supplemental testimony was filed.

BY MR. MEHTA:

Q. And you testified at your prior deposition, Mr. Hart, at least as I recall it, that the Attorney General's office asked you to look at the time value of money method over different dates sometime in the last week of February of 2020, is that correct?

MS. TOWNSEND: Objection. If we could refer to the deposition page, that would help, Kiran.

MR. MEHTA: Yeah, sure. I think the deposition, do you have it available, Mr. Hart? I think we marked it as Exhibit No. 8.

THE WITNESS: Yes. I have it,

yes.
BY MR. MEHTA:
Q. And if you would, turn to page 75.
A. Okay.
Q. The question at line 15 is why did you do it, which is the calculation, after your testimony was filed? And your answer was it was something that the DOJ asked me to do, look at different -- to look at the time value of money over different dates. Do you see that?
A. Yes.
Q. So it was the DOJ or the Attorney General's office, your client, that asked you to look at the time value of money method over different dates, correct?
A. Yes. So I had looked at the time value of money, and had discussed it with them and then we discussed doing several different dates.
They didn't ask me to do a time value of money calculation to begin with. I already had done that, and then we discussed doing it for several dates.
Q. And when had you discussed doing a

time value of money analysis with your client, the Attorney General's office?
A. I think we discussed those early as probably January. That was one of the methods I was looking at.
Q. So before you filed your original pre-filed or before the Attorney General filed your original pre-filed testimony, correct?
A. Oh, yes, yes, I had talked about the time value of money as a way to evaluate cost reductions for not addressing groundwater contaminations.
Q. I'm sorry, Mr. Hart, you faded on me on that answer.
A. So I had discussed with them the time value of money calculation as a method of evaluating the reduction in cost that were being included in the rate case as a way to -- if they had started sooner addressing the coal ash basin as a result of the detection of groundwater contamination.
Q. So was the idea of trying to measure this reduction in cost through the

time value of money method your idea or the Attorney General's idea?
MS. TOWNSEND: Objection, asked and answered.
THE WITNESS: That was my idea.
BY MR. MEHTA:
Q. And back on page 75 of your deposition transcript, down at the bottom of the page, you indicate that somewhere in the last week of -- the question was asked, somewhere in the last week of February you were asked to do something, correct?
A. Are you talking about line 17 to 19.
Q. I think it's further down from that. It looks like it's line 23 and 24.
A. I'm not sure I understand that question. I'm sorry.
Q. Well, at line 23 and 24, line 23, the question is so somewhere in the last week of February, correct? And your answer on 24 is correct. Do you see that?
A. Yes.
Q. And then if you go back up to line

17 to 19 is -- what is it that you were asked to do in the last week of February?
A. So I had done some calculations using start time I believe in the early 2000s to 2009 time frame or 2010, I can't remember specifically, and then they suggested looking back to some of the earlier times when DEC knew about groundwater contamination.
Q. And when you say "they suggested," you were talking about the Attorney General's office?
A. Yeah, I'm sorry, the DOJ, yeah.
Q. And, Mr. Hart, is it correct that what you are trying to show through the time value of money methodology, is the difference between the cost of work being done more or less today, contemporaneously, to what it would have cost if it had been done at those various earlier points in time that you testified about?
A. Yes, I would say in a general sense, yes, assuming that -- sorry.
Assuming that what is being done

today would have been done previously, which I think probably what's being done today is on the high side of what have been done previously.

So, again, I think it underestimates the actual costs that would have been incurred previously. So it's a minimum, as I discussed before, minimum estimate.

Q. Just to make sure I understand the tasks that you were given and that you attempted to perform, is it correct that the task was to calculate that portion of the costs for which Duke Energy Carolinas seeks recovery in this case should be disallowed due to what the attorney general believes was Duke Energy Carolinas past imprudence?

A. No. What I was asked to do was evaluate the data and information to determine if DEC responded appropriately to the presence of groundwater contamination, and if they had done that sooner because of the presence of groundwater contamination from their coal

ash basins, would the cost be -- what difference in cost that would be.

Q. Let me try to break --

A. Okay.

Q. Go ahead.

A. Well, between what they are asking for today versus what they would have incurred previously.

Q. So if I'm understanding you correctly, the object of the exercise was to determine the difference between what Duke Energy Carolinas was asking for today and what it would have asked for at these earlier points in time?

A. Well, yeah, I don't know if it would have had to ask for a rate increase at an earlier point in time.

Q. Assuming that they would have had to have asked for a rate increase to cover these costs, what you were trying to determine is the difference between what is being asked for today and what would have been asked for at these earlier points in time, is that correct?

A. Yes. Again, assuming that the --

those actions previously would have been similar to the actions today.

Q. Now, you indicated in your deposition, and I'm looking at pages 76 -- I think it's 76 and 77, where you discuss that this was a joint decision between you and the Attorney General's office to include quantification as measured by the time value of money method in your analysis. Am I capturing that correctly?

MS. TOWNSEND: Objection. Getting close to attorney work product here.

MR. MEHTA: Well, Ms. Townsend, I really don't think that attorney work product involves the instructions that the attorney provides to a testifying expert witness.

But I think you are not directing the witness not to answer that question, so the witness can answer that question.

THE WITNESS: We had discussed including specific costs. At the time of the pre-filed testimony, we decided not to include specific costs.

But we did discuss it was brought

up in my deposition to discuss specific costs before my deposition.

BY MR. MEHTA:

Q. In connection with these discussions, did you discuss any method of quantifying these costs other than the time value of money method?

MS. TOWNSEND: Again, objection.

THE WITNESS: Yes, I would say in a general sense I had discussed that there were some early closure costs and costs for things like dry ash conversion in some of the DEC documents, but they were in some cases difficult to decipher exactly what was included, whether it was full dry ash conversion or just fly ash conversion, and what was included in the basin closure costs.

So it was difficult using the information in the DEC documents to come up with specific costs that they were looking at at that time with some degree of certainty.

BY MR. MEHTA:

Q. Because it was difficult to do it

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with what you considered to be the requisite amount of certainty, you did not follow any of those alternate paths towards trying to quantify these costs, correct?

A. Correct. I didn't feel like I had enough background information or specific bases for some of those costs. They were just in a spreadsheet, for example.

Q. Now, Mr. Hart, you have alluded to this already a little earlier in the deposition, but if you flip over to page 129, lines five through ten.

This is 129 of your supplemental testimony, lines five through ten.

A. I'm sorry, I was looking at my deposition. Page 129, okay.

Q. There you indicate that the performing your time value of the analysis, you assumed that "the activities that DEC is requesting cost recovery for at this time are similar to the activities that would have been conducted at an earlier time," correct?

A. That's correct.

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Q. What is the basis of this assumption?

A. Well, it's just an assumption that those activities are taking place now. So we have some degree of certainty of what the costs are for those.

Again, as I said before, I believe that there is a potential, a likely potential that costs would have been lower previously because they were doing -- now they are doing full excavation.

There is beneficiation ongoing, things like that, that certainly are higher cost alternatives than might have been taken earlier.

So, if anything, this approach underestimates the previous -- the cost that -- the lower cost that might have been incurred previously.

Q. So were the legal and regulatory requirements at any of those earlier points in time that you evaluated, similar to the legal and regulatory requirements today?

MS. TOWNSEND: Objection.

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THE WITNESS: Well, certainly the 2L standards still apply throughout this time period. Things like hazardous waste determination still apply. Things like disposing of waste in landfills still applies, or use for beneficial fill -- or use of coal ash for beneficial fill, all those apply now.

BY MR. MEHTA:

Q. Were the technologies available today available at any of those earlier time periods that you evaluated?

A. Potentially certainly excavation was certainly available back then. Things like thermal beneficiation, probably not. There may be others.

Q. I guess a different way of asking that question would be, Mr. Hart, have there been innovations with respect to technology available today that would not have been available to be used at those earlier time periods because they didn't exist?

A. The only one I can think is probably something like thermal

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beneficiation, and that was probably not well proven -- well, it depends on what time you're talking about.

Certainly not in the 1980s. Maybe in the 2009 there was some valuation going on, but I don't know if there was any demonstration for thermal beneficiation.

Certainly there have been other types of beneficiation done for different industries.

Q. And you did not attempt to go back in time and assess that a thermal beneficiation was not available -- was available and what that would have cost at those earlier points in time, correct?

A. Well, it's clear from the work that EPRI did for Duke, that thermal beneficiation was by far the most expensive method of addressing wet ash and even -- I think that you needed to have a 20 year supply of ash to recover the cost associated with it.

So it's going to be any method that you evaluated previously is going to be lower cost than the costs that are

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being incurred now for thermal beneficiation.

Q. But you did not go back to assess what that lower cost would be, did you?

A. No, because in my analysis it would actually underestimate what the lower cost would be. By far thermal beneficiation is the most expensive method.

Q. Mr. Hart, you are a geologist and specifically a hydrogeologist, correct?

A. That's correct, yes.

Q. What does a hydrogeologist do?

A. Well, some hydrogeologists look at water resources, developing water resources.

There are some that deal with contamination issues. They determine the types of contaminants present, the nature and the extent of the contamination, methods to remediate the contamination, methods to address the sources of contamination, would all be part of things that hydrogeologists do.

Q. And that's what you do in your

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professional capacity as a hydrogeologist, right?

A. I work primarily with contamination issues, yes. Not on the water -- I don't do much work with water resources.

Q. Mr. Hart, again, you are fading and I'm wondering, is your audio working through the computer or are you on a phone for the audio?

A. No, I'm on a phone. I'm in our conference room and we have speakers in our conference room tables.

We do have a microphone, although I hate to say I would look kind of goofy.

THE VIDEOGRAPHER: Mr. Mehta, can we take a break? This is the videographer.

MR. MEHTA: Yes.

THE VIDEOGRAPHER: We are going off the record at 10:20 a.m. This is the end of media number one.

(Recess was taken from 10:20 a.m. to 10:29 a.m.)

THE VIDEOGRAPHER: We are back on

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the record at 10:29 a.m. This is the beginning of media number two. Go ahead.

BY MR. MEHTA:

Q. Okay, Mr. Hart, in the group of exhibits that was sent to you prior to the deposition is Exhibit No. 7, which is a list of your cases in which you have provided prior testimony. Do you have that list?

A. Yes, I do.

Q. And in each one of these cases -- I'm sorry, in each one of these cases, you provided expert testimony in your capacity as a hydrogeologist, is that right?

A. Yes, either in deposition or in trial, yes.

Q. If you could, we could just take them in order, but the very first case is called MSC. Apparently it was pending in the Western District of Arkansas.

Just very briefly, what was that case about?

A. That was a case about the Transmontaigne Partners and Razorback, which was a pipeline for petroleum fuel

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products that overfilled a large tanker by about -- and they had a release of I think it was around 75,000 gallons of gasoline, that had impacted an adjacent property.

And so I was working for the plaintiff in evaluating the appropriateness of the response actions, assessment, contamination on the property, things of that nature.

Q. Did you have occasion to use the time value of money methodology in connection with this case, the MSC case?

A. I can't recall. There was -- I think we did do a cost estimate for remediation in that case for the plaintiff's property, and in that we would have used a time value of money calculation to discount for future costs. So I would say yes.

Q. So what you were doing there is discounting future costs to the present in order to understand what money would be owed in the present to cover those future costs, is that correct?

A. Correct.

Q. So in the second case, Mr. Hart, the Harold Cushman case in Horry County, South Carolina, what was that case about?
A. AVX Corporation had a chlorinated solvent releases from historical manufacturing operations at their facility, and groundwater contamination had impacted certain properties offsite, downgrading of their facility.
So I worked for AVX Corporation in evaluating -- there are allegations that it impacted a very large area, so we looked at alternate sources of contamination, including things like dry cleaners that were in the area, and then just the response actions that have been taken by AVX and their appropriateness.
Q. I take it you opined they were appropriate?
A. I mean their remediation efforts were, yes.
Q. Is that case connected to or related to the third one on your list, which is also an AVX Corporation case?
A. Yes, it's related to the other

case, same facility, although AVX sued Horry Land in the United States of America for contamination contribution.
The AVX Corporation was -- part of it was on in downgrading of the Myrtle Beach Air Force Base.
THE COURT REPORTER: I'm sorry, I --
BY MR. MEHTA:
Q. In either of those two matters, the AVX matters, Mr. Hart, did you have occasion to use the time value of money methodology?
A. I don't believe so, no.
Q. So then the fourth case is Ruffin -- W. Rufin Woody, Jr. versus Eaton Corporation in Person County, North Carolina. What was that case about?
A. It was about groundwater contamination from the Eaton facility. I believe it was in Roxboro where a chlorinated solvent plume had impacted some offsite properties.
Q. And was your client Mr. Woody or was it Eaton Corporation?

A. It was Eaton Corporation.
Q. Are what were you asked to do in that case?
A. I was asked to evaluate if Eaton had appropriately responded to the offsite contamination, and were the activities done by their consultant in accordance with the North Carolina REC program appropriate and in accordance with the REC program.
And then I believe I looked at which properties -- I believe Mr. Woody owned several properties, and which properties were contaminated and the extent of contamination on those properties.
Q. Did you have occasion in this case, the Eaton Corporation case, to use the time value of money methodology?
A. I don't believe so, no.
Q. The fifth one on the list involves Whirlpool Corporation, also in the Western District of Arkansas. Can you tell me what that matter was all about?
A. That was a plume of groundwater

contamination was associated with the Whirlpool facility in Fort Smith, Arkansas, that had impacted a residential area.
And so I was working for plaintiff's attorneys for the residences -- residence, I'm sorry, and assessing the adequacy of their delineation of the contamination, the potential for vapor intrusion issues, cost of remediation, delineation of the contamination. That's what I recall.
THE COURT REPORTER: I'm sorry, can you just repeat -- is it bacrant trusion?
THE WITNESS: Oh, I'm sorry, vapor, v-a-p-o-r.
THE COURT REPORTER: Vapor intrusion?
THE WITNESS: Yes.
THE COURT REPORTER: Okay, thank you.
BY MR. MEHTA:
Q. And in this matter, Mr. Hart, did you have occasion to utilize the time

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value of money methodology?
A. I believe so. Yeah, I believe we came up with a cost estimate for remediation of the plaintiff's property, which included a time value of money calculation.
Q. And is this, again, a cost estimate that went out into the future and you were discounting back to present value?
A. Yes.
Q. All right, the next one on the list is Brent Walker and Devan Walker versus Lion Oil in Columbia County, Arkansas.
You seem to have a lot of Arkansas matters, Mr. Hart. Were you halfway residence at the time in Arkansas?
A. No. I just have done work for an attorney out there for a long time on groundwater contamination issues.
Q. All right. And in this particular matter, the Brent Walker and Devan Walker, were you representing or were your clients the plaintiffs, the Walkers?

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A. Yes, they were.
Q. And tell us about what this matter was?
A. So Lion Oil had had a release of crude oil from what they call an intermediate bulk station, which is where they take oil from a number of wells nearby and then bulk it for transport.
And they had overfilled the tank and it had impacted Mr. Walker's property as well as a significant area downstream of the Walker property.
So we did an evaluation of what residual contamination was on the property, and the cost for cleanup of the property.
Q. And again, did you have occasion to use the time value of money methodology in connection with the Walker case?
A. I don't recall. I know we did a cost estimate. I think it was just a cost estimate for soil removal. So I don't think it would have included any future value costs.
Q. You were simply evaluating what in

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effect the present dollars amount would have been for soil removal as opposed to stretching it out over time in the future, is that right?
A. Right, yes, that's correct.
Q. The next one is Teresa Price and Thomas Price versus US Gear and others, in the Western District of North Carolina.
Can you tell us what that one was about?
A. Yes, so I worked for Textron in that case and the Prices alleged that groundwater contamination in their water supply well was from the US Gear Tools facility, which had been I believe previously owned by Textron, and I guess Micromatic at one time.
So we did an assessment of groundwater conditions. We installed a number of additional wells. We did some fairly detailed geologic evaluation to determine the source of the contamination in the water supply well on the Price property.
Q. Did you have occasion to use the

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time value of money methodology in connection with this case, the Textron case?
A. No.
Q. The next one is Day, LLC and Kent Upton versus Plantation, I assume it's Pipeline Company?
A. Yeah, should be Pipeline. Yes.
Q. Northern District of Alabama. What was that case about?
A. Plantation Pipeline had had a release on its pipeline in the area that Day, LLC and Kent Upton property, where they -- it was on top of what they call double mountain.
They had a release, and so it was Plantation Pipeline and Kinder Morgan evaluating the adequacy of their response actions, if they had removed the free product or whether there was still residual free product left.
This is a release of gasoline that looked at the impact to the creeks nearby and time frames for remediation.
Q. I'm sorry, which side of the V

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were you on in this case?
A. I was working for Plantation Pipeline and Kinder Morgan.
Q. Did you have occasion to use a time value of money methodology in the Kinder Morgan case?
A. No.
Q. The next one is Larry David Shepherd, and Sheila Diane Shepherd versus Eco-Energy?
A. Yes.
Q. Rowan County, North Carolina. What was this case about?
A. Eco-Energy had a tanker truck of ethanol that was going down the highway and overturned onto property owned by Sheila and Larry Shepherd, causing contamination of their property from ethanol, some petroleum fuel from the saddle tank and also PFAS from a significant quantity of aqueous film forming foam was placed on this release.
So it had contaminated their property and water supply wells with PFAS, as well as initially ethanol.

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Q. And PFAS is P-F-A-S for purposes of the court reporter, right?
A. Yes, all caps, yes.
Q. Was your client in this case the Shepherds or was it the Eco-Energy group?
A. It was the Shepherds.
Q. And did you have occasion to use the time value of money methodology in connection with your work on this case?
A. I believe so, yes, did a cost estimate for remediation, which included long term groundwater cost.
So I believe it included a future value, evaluation for future costs.
Q. And again, the purpose for your use of the time value of money method there, was to take those costs stretching out over the future and bring them back to present value through some kind of discounting, is that correct?
A. That's correct, through some sort of inflation rate discounting, yes.
Q. And the last one on your list, Mr. Hart, is Michael Shannon Beck versus Duke Energy Carolinas in Stokes County, North

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Carolina, is that right?
A. Yes, that's correct.
Q. And what was -- I assume you represented Michael Shannon Beck in this particular case, right?
A. Yes, as well as a number of other property owners near Mr. Beck as well that were down gradient of the Dan River facility, that alleged continuing impact from the Dan River spill, coal ash on their properties.
Q. Is this case completed or is it still ongoing?
A. It's completed.
Q. And what were you asked to do in connection with the Michael Shannon Beck case?
A. We were asked to look at each of the properties and look for visual evidence of coal ash, and then also took samples for analysis of both metals as well as Cenospheres to evaluate the presence of coal ash.
Q. And did you have any occasion to use the time value of money methodology at

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this particular case?
A. No. Well, hold on, I can't remember. We may have done a cost estimate. I can't remember. May have done a future value evaluation, but I honestly can't remember. I think it was just soil removal. So I don't think so.
Q. I understand from counsel for the AGO, that you prepared an affidavit of some kind in that case.
So to the extent that you did use a time value of money methodology, it would be reflected in that affidavit, is that correct?
A. Yes. I don't think I did --
Q. Yeah, if it was simply soil removal, I'm guessing that you probably did not. Is --
A. Yeah, I think it was soil removal, but just some -- there were some costs in there for groundwater monitoring just to determine if there was groundwater contamination, but as far as I recall, no cost in there for long term monitoring.
So we wouldn't have done a time

value of money evaluation. I'm pretty sure we did not.

MS. TOWNSEND: If I may interject, Kiran, I believe that was in the -- the Beck case was in Rockingham County, not Stokes. Is that correct, Steve?

THE WITNESS: Oh, you are right, yes, that's correct.

MS. TOWNSEND: I just wanted to make sure the record was clear.

BY MR. MEHTA:

Q. I don't know where Stokes came from, but my guess is it was something that got produced, but if Rockingham is the correct county, we'll make that adjustment.

A. Thank you.

Q. Mr. Hart, in your initial testimony, the direct testimony in the Duke Energy Carolinas case that was filed back in February, that was Exhibit No. 1 to your deposition taken back in March, I don't know if you have that testimony handy.

A. I don't think I have it right in

front of me.

Q. If not, I will just refer to a particular line which you can -- do you recall our subject to check rubric for Utilities Commission purposes?

But Subject to check, on page four of that testimony, you indicated lines 18 through 23, that you testified multiple times in state and federal courts, qualified as an expert in the areas of geology, hydrogeology, fates and transport of contaminants in the environment, contaminant source identification, site assessment and remediation, exposure potential, adequacy of response actions and remedial methods and costs.

Does that sound right subject to check?

MS. TOWNSEND: I have it in front of me, and it is correct, Steve, for your information.

THE WITNESS: Yes. Yes, that sounds correct.

BY MR. MEHTA:

Q. And in any of these cases, did you

testify at trial or were they all deposition testimony, the ones in your -- in Exhibit No. 7?

A. Some of them were in trial. The first one, MSC, was in federal court trial.

Number three, AVX versus Horry Land was in federal trial. I mean, I testified in federal court, same as number one.

All the other ones settled before trial that are on this list.

Q. So were you qualified as an expert by the trial judge in the MSC case in the areas in which you testified?

A. Yes.

Q. And I believe you indicated that in that case, part of your testimony had to do with the cost -- estimated cost of remediation, and you performed a present value calculation in connection with that testimony, correct?

A. I believe so, although it's been 12 years, but I think so, yes.

Q. So if that is the case and were

you qualified as an expert to testify about that present value calculation with respect to the future damages in the MSC case?

A. I'm sorry, could you repeat the question, please.

Q. Sure. That was probably an unclear question. Were you qualified as an expert by the trial judge to testify about the present value of the future damages experienced by your client in that case?

A. As far as I can recall, yes, but it's been awhile, so I would have to -- I mean, I have -- subject to check.

Q. All right. Thank you. Apart from that case, have you ever been qualified by a judge as an expert with respect to the time value of money methodology?

A. Well, I mean, I have been qualified as an expert with regard to the cost of remediation, which include the time value of money.

I believe there was the MSC case and there was also one in the federal

court in South Carolina where I did analysis of costs to remediate property from a solvent released at a plant.
And I can't remember what city it was in, but somewhere in the upstate.
Q. That case is not on your list. That's Exhibit No. 7, is it?
A. It is not. So we I believe in consultation with DOJ were limited to the last ten years or so.
Q. So that case was --
A. So there are other cases where I testified in deposition or in court that are not on this list.
Q. Apart from the one that you just mentioned in the upstate South Carolina, were there others in which you employed the time value of money methodology?
A. You mean where I testified in court?
Q. Or provided deposition testimony or an expert report?
A. I know there was another case in Arkansas that I testified in state court regarding, again, remediation from -- it

was from a bulk fuel terminal, and I know we did a time value of money estimate for that in that case as well that was -- that was in trial.
Q. And then in connection with any of these time value of money analyses that you have done, Mr. Hart, is it correct that what you have done is taken the future costs to be experienced by the claimant in the case, and brought them back to a present value so that the claimant can be made whole in terms of the money that the other side needs to pay that claimant?
A. Yeah, I would say in a general sense, yes, it assumes that the plaintiff would get a lump sum of money over remediation costs at present day, and some of that money would earn money through interest rate or -- or -- sometimes you can make a case that the interest rate and inflation cancel out each other.
So we are looking at -- I'm sorry, I'm not being very clear. So we are looking at discounting the cost for its

future value if you receive a lump sum payment today for the remediation cost.
Q. In order to ensure that claimant receives that future value in a lump sum today, correct?
A. Correct.
Q. Now, Mr. Hart, I want to explore with you the mechanics of the time value of money methodology that you used in the Duke Energy Carolinas case.
I think maybe the easiest way to do that is to take a look at Exhibit No. 3, which is your work papers for the DEC case?
A. Okay, right.
Q. And sort of use the work papers in conjunction with the actual supplemental testimony, which I guess is Exhibit No. 2. And looking at Exhibit No. 2 on page 130, line 15, you have a figure of $405,975,531, right?
A. Yes.
Q. Where did this number come from?
A. I believe it came from Ms. Bednarcik's testimony.

Q. Her direct testimony in the Duke Energy Carolinas case?
A. Yes.
Q. And I ask because actually if you flip over to Exhibit No. 6, Mr. Hart, which is your Duke Energy Progress work papers.
A. Okay.
Q. The presentation between the two work papers is different. Well -- because you can see on the very first tab of the Duke Energy Progress work papers, Exhibit No. 6, there is a plant by plant breakdown of costs. Do you see that?
A. Yes.
Q. There is nothing like that on Duke Energy Carolinas work papers, which is Exhibit No. 3?
A. Correct.
Q. So I can tell what you are doing in Exhibit No. 6 because it goes plant by plant and the numbers match up to Ms. Bednarcik's Duke Energy Progress testimony.
But the same is not true with

respect to the Duke Energy Carolinas work papers, Exhibit No. 3. But I will take your word for it that the 405,957,531 comes from Ms. Bednarcik's direct testimony, and subject to check, we will check that out.
A. So, yeah, after my original deposition in the DEC case that you wanted my work papers, so I put them together just what I had done within a day or so, whereas in the DEP case I spent more time maybe bringing it up so you could follow easier, which I hadn't done because you had asked for my work papers that I had at the time of my deposition.
So I did spend more time, obviously, and the analysis was a little more complex for the DEP case.
Q. Just to make sure you don't have any revised or updated work papers for the DEP case, do you?
A. No.
Q. Wherever the $405,000,000, almost $406,000,000 figure came from, if it is from Ms. Bednarcik's direct testimony, it

is on a complete system basis, is that correct?
MS. TOWNSEND: Objection. You might want to explain what that means, Kiran.
BY MR. MEHTA:
Q. Do you know what it means, Mr. Hart?
A. My understanding is would be for the whole system and only a portion would be attributable to North Carolina ratepayers, as I understand it, although I'm not perfectly clear.
So yeah not every -- as I understand it, not every bit of the 405 or almost 406,000,000 would be system cost to treat it to North Carolina ratepayers.
Q. So whatever calculations or whatever the result of your calculations, they are also on a system basis, is that correct?
A. Yes. Yes. I don't know how the different -- how you -- the Utilities Commission or whoever makes whatever adjustments they need for North Carolina

versus other places.
So I just took the total system cost, that's correct.
Q. And the time frame over which the costs compute to 405, almost $406,000,000 is whatever the time frame is in Ms. Bednarcik's direct testimony, is that correct?
A. That's correct, for the DEC case, yes.
Q. And in the work papers, Exhibit No. 3, you address four different time frames, correct, 1989, 1995, 2003 and 2010?
A. Correct.
Q. Did you follow the same method of calculation for each time period?
A. Yes.
Q. So we don't have to look at all four of them, we can just look at one of them to understand what you did, is that right?
A. Yes, that's correct.
Q. So let's look at 1989 as an example. You have labeled as "revised

cost the number $342,100,515, which is in cell looks like H7," correct?
A. I don't have this. I just printed out the exhibit, but yes -- I don't have the cell number, but yes, revised cost $342,100,515, yes.
Q. And you arrived at that by taking the total cost from Ms. Bednarcik's testimony, of 405, almost 406,000,000, removing the fulfillment fee and removing water supply costs, right?
A. Correct.
Q. And then if you don't have the native file, I will tell you it is in cell E10, there is a figure of $171,500,000. Do you see that on your printed out spreadsheet?
A. Yeah, I see that. Yes.
Q. Where did that come from because on the native spreadsheet it's just a plug in number? It's not a calculated number.
A. That's right. So what the calculated number is, is the several cells over is the 342,843,293.06.
So what we do is just use a future

value calculation and plug in numbers until it closely matched the revised cost of 342,100,515, to come up with -- at the average inflation rate over that time period, which is 2.7 percent over 26 years, and that number was 171,500.

So it's a trial and error to get as close as -- to the 342,100,515 to get that number, which is represented by 342,843,293 to get it as close to possible to the $342,100,515.

THE COURT REPORTER: I'm sorry, it's the court reporter. You have to slow down.

THE WITNESS: Sorry.

THE COURT REPORTER: Sorry, the numbers you just have to slow down for me.

THE VIDEOGRAPHER: One other thing, with the numbers, you guys have to say them out 5,500,000. You follow me?

THE COURT REPORTER: I am not sure when you say 342-100-515. I mean I am just typing down numbers when it's like that.

BY MR. MEHTA:

Q. Okay. Well, that would be $342,100,515.

I think, Mr. Hart, you were trying to tell us how you came up with the number 171,500,000, which is in cell E10.

And if I understood you correctly, correct me if I'm wrong, but what you did was essentially by trial and error, using a future value calculation dated from 1989, you came up with the number that's in cell H10, $342,843,293.06.

That was "close enough to your revised cost number." Did I capture that correctly?

A. Yes. I mean, it was within rounding errors, yeah.

Q. Why didn't you just take the revised cost and discount it back to 1989?

A. Well, I don't know. I like mine the way I did it. I mean you could do that.

The way I did it, I like to say if I was sitting here in 1989, and I waited 26 years, how much more would it cost me?

Q. In any event, how you came up with

the 171,500,000 number that is in cell E10 was essentially through trial and error?

A. Correct, until it came close to the revised cost, that's right.

MS. TOWNSEND: Kiran, we have been going at this since 9:30. It's now 11:20.

Do you have plans for a break at sometime soon or what's your thought?

MR. MEHTA: I think we will be able to wrap up the DEC part in the next probably half hour or so.

Let's try to do that, and then we can start fresh with the DEP part maybe after a short lunch break or something like that, if that works for you, Terry.

MS. TOWNSEND: What about you, Steve? You are the one sitting in the hot seat.

THE WITNESS: Yeah, that's fine with me.

MS. TOWNSEND: Thank you, Kiran.

BY MR. MEHTA:

Q. Sure. Now, Mr. Hart, the calculation that you make indicates that the entirety of the revised cost as if it

had been incurred in 2014. Have I captured that correctly, and discounted to 1989 in your trial and error methodology?

A. I'm sorry, say that again.

Q. If I'm reading the spreadsheet correctly, and I'm looking at the native form so that I can see some of the formulas, it looks to me like what you did was take the revised cost as though it had been incurred in 2014 because the future value of that 171,500,000 number goes up to 2014?

A. Right. So the Bednarcik testimony covered a very small window, maybe a year or so, year and a half.

So, yes, it assumes it's within generally that time frame of a year.

Q. Well, the Bednarcik testimony reflects work that was done in I think you are right, a year and a half, but it was 2018 and maybe through June 30th of 2019. Is that how you recall it?

A. Roughly, yes. What I'm saying is if that work had started in 2014, in that time frame, that's what the cost would have been, rather than starting in a time frame that's being done now.

Q. Why didn't you future value it to 2018, 2019 as opposed to 2014, since it's being done in 2018, 2019?

A. What I'm saying is if they had started sooner, those costs would have been incurred -- costs that are incurring now would have been incurred earlier. So this, it actually results in a lower cost.

Q. What you are saying is the costs that are being incurred now, would have been incurred in 1989, correct?

A. If they had started in '89, right. What I'm saying is they should have -- if -- they started in 2014 is what I'm saying.

If they had started in 1989, the cost would have been this much lower.

Q. But the cost --

A. Does the same activity --

Q. Go ahead. Sorry.

A. If they had started those same costs in 1989, the same procedures they have already gone through, the evaluation

of the coal ash ponds and the planning for closure and closure of the plant, if they started then, the cost would only have been 171,000 or 171,000,000 versus when they started in 2014.

Q. But the actual work that you are evaluating occurred in calendar year 2018 and half of calendar year 2019, isn't that correct?

A. Yes.

Q. And so the actual work that you are evaluating is not the beginning of the project in the DEC plants, but several years into the project at the DEC plants, isn't that correct?

A. Right, but it's the -- I'm trying to think how to explain it.

Q. Let me just ask you this way. Why didn't you future value to the time in which the work is actually being done, 2018, 2019, as opposed to future valuing to 2014?

A. Well, I was trying to give credit for them starting in 2014. They didn't start in 2019. This is an evaluation if

they had started sooner.

Q. Why did you pick 2014?

A. That's when they started because the Dan River spill to work on coal ash basin closure and planning, and that kind of thing in any significant way because of the CAMA rules and pre-CAMA requirements.

Q. So are you saying they did no work prior to the Dan River spill or pre-planning on basin closure and things of that nature, they meaning Duke Energy Carolinas?

A. I haven't seen much. They did some I would say, but not a significant amount.

Q. Well, they did -- they did plenty of cost estimation for basin closure prior to the Dan River spill, did they not?

A. They did do some cost estimation, yes.

Q. Is that planning associated with potential closure of the Dan River?

A. It's a step, but it's not any step towards what I would call physical closure, but it is a step, yes.

Q. Was any of that work done prior to the Dan River spill -- did it impact the work that was done after the Dan River spill in your estimation?

A. I did not -- I mean it seems like they from the reports I have seen that the evaluation of alternatives to the extent it may have been done before was done by outside consultants.

Q. Does it matter who it was done by, as long as it was done for Duke Energy Carolinas?

A. Well, I think my point is that I don't know -- it doesn't look to me like the outside consultants started with any of Duke's other than maybe a cost estimate, and I think Duke had looked at closure costs, but that's not equivalent to how are we going to close -- the three alternatives, that kind of thing.

I had not seen that kind of analysis was done before the Dan River spill.

Q. So when you are talking about the three alternatives, what are you talking about?

A. Well, I mean in some cases -- I won't say three. There may have been five, but they generally looked at closure in place in the work that was done by outside consultants.

THE VIDEOGRAPHER: WE have to go off -- okay, we are fine. The witness was frozen for a second.

THE WITNESS: Sorry.

THE VIDEOGRAPHER: It's okay. We are fine. We can keep going.

BY MR. MEHTA:

Q. Okay, you were talking about the three alternatives --

A. Yeah, I don't say --

Q. To the Dan River spill.

A. Right, generally there were three alternatives that were considered after the Dan River spill. One was in place closure. One was some sort of hybrid alternative of maybe excavating some of the ash, and using it in a closure in place process, and then there was some full excavation cost.

Now there may have been some variance on that, but there was just three. In some cases I think there was five or six options, but those were the three I would say general categories that were used.

In the documents that I reviewed, it was mostly we think -- I mean prior to that, there were some cost estimates for in place closure primarily.

Now, there may have been some that said if we had to fully excavate it here is what the cost would be, but I didn't see any in depth planning for basin closure before the Dan River spill.

Q. And did you pick 2014 because that's when the Dan River spill was?

A. Well, that's when it was obvious -- well, the CAMA rules were coming out or had come out, and there were directives like even before CAMA came out for DEC to close basins like at Dan River, and I think River Bend or at least to move them away from the river, that kind of thing.

Q. That's why you picked 2014?

A. Yes.

Q. And Mr. Hart, you indicate that the period between 1989 and 2014 is 26 years. Is that what your spreadsheet says?

A. Yes.

Q. Is it 26 years or 25 years?

A. Well, I guess it depends on when you start. You start at the end of the year or beginning of the year.

Q. Is there some convention in the time value of money methodology where you start and where you end?

A. I started in the beginning of 1989 and went to the end of 2014, assuming annual payments, I believe, is through those 26 years.

Q. My question to you was, is there a convention in the time value of money methodology as to when you begin and when you end?

A. I mean not that I'm aware of, no.

Q. And the Dan River spill itself was very early in 2014, was it not?

A. Correct.

Q. I think it was on Superbowl Sunday, which would have probably put it in the very early part of February of 2014, correct?

A. I believe it was February 2nd or 4th. I can't remember the date, so yes.

Q. But you ended up using 26 years because you started on January 1, 1989 and ended at December 31st of 2014, is that right?

A. Yes.

Q. And then, Mr. Hart, in cell H11, there is the figure $171,343,293.06. Do you see that?

A. Yes.

Q. And the formula says that is the result of the number in H10, which is immediately above it, and you subtract the number in E10, which is 171,500,000 to arrive at the figure in H11, correct?

A. Yes.

Q. And you describe that number in H11, $171,343,293.06 as the difference between the revised cost and equivalent

cost 26 years earlier, correct?
A. Correct.
Q. I guess what you mean is, it's the difference between a revised cost as future valued from 1989 with a start value of $171,500,000 and $171,500,000, correct?
A. Yes, that's correct.
Q. And that is how you applied your time value of money methodology for purposes of this case, correct?
A. Yes.
Q. Are there any standard texts that support your application of time value of money value methodology in this way, Mr. Hart?
A. I'm not sure I understand your question.
Q. Well, I'm not sure how to make it clearer. Are there academic articles, texts, books, that say this is the way you should apply a time value of money methodology the way you just described it?
A. Well, I mean it's certainly a simplified method. Yeah, it's a standard methodology. If you say, well, in 1989 if

I had $171,000,500, that cost in 19 -- I'm sorry, 2014 at an average inflation rate would be roughly 342,000,000. I mean it is simplified, but it is a standard methodology, yeah.
Q. What I was really asking you, Mr. Hart, is there a standard text or a peer reviewed article that supports subtracting that 342,000,000, which is the end result from the 171,000,000, which is the beginning number to arrive at a "different"?
A. That's just the difference between what the costs are today, versus what they would have been starting in 1989. That's all.
Q. Are you aware, Mr. Hart, of any standard text or peer reviewed journal that supports the application of the time value of money methodology in that fashion?
A. I mean to me it's a standard methodology that is the difference between cost. If you had started in 1989 planning for closure costs, versus starting in

2014.
Q. So is the answer to my question, is there a standard text or a peer reviewed article that you don't know?
A. I don't know of one. To me it's a standard -- it's a -- you have taken the cost starting in 1989, and assuming here is the activities occurring five years later that if you had started in 1989, as opposed to starting in 2014, and saying what's the time value of money for that.
It's just the difference between the two.
Q. So the answer to my question is you are not aware of a text that supports your application in the subtraction between those two different years of the time value of money methodology?
A. Subtraction -- I don't know what specific methodology you would want, but I'm not aware of any other than just it's subtraction.
Q. Now, in your supplemental testimony, Mr. Hart, which is Exhibit No. 2, I'm looking at page 130.

At the top of that page, you have got four bullets that detail or that state for 1989 the difference in cost is $190,000,000.
For 1993 it's $140,000,000. For 2003 it's a $100,000,000 and for 2010 it's $50,000,000. Did I capture that correctly?
A. Yes.
Q. None of those numbers, 190,000,000, 140,000,000, 100,000,000 or 50,000,000 are in your work papers are they, Exhibit No. 3?
A. No, they are just rounded. They are just rounded numbers. I mean 188,870 -- the 188,870,363.06, I rounded to 190,000,000.
Q. Okay. Mr. Hart, I think I have come to the end of my questions on the DEC supplemental testimony, although I may think of a few as we go on a break.
But my intention would be to shift over to the Duke Energy Progress testimony after break, and I'm open to anybody's suggestion as to how long we should have a

break, but let's do that off the record.
We could go head and go off the record.
THE VIDEOGRAPHER: We are going off the record at 11:39 a.m. This is the end of media number two.
(Lunch recess was taken from 11:39 a.m. to 12:31 p.m.)
THE VIDEOGRAPHER: We are back on the record at 12:31 p.m. This is the beginning of media number three.
BY MR. MEHTA:
Q. Good afternoon, Mr. Hart. Turning to your Duke Energy Progress testimony, which we previously marked as Exhibit No.'s 4 and 5, and just most of my questions I think will concern the public version, so keep Exhibit No. 4 handy.
To start with, Mr. Hart, look at the paragraph beginning at page five, line 16 of Exhibit No. 4. The questions that you put forth in the paragraph are the same two questions you asked yourself in connection with your DEC testimony, is that right?

A. Yes. Yes.
Q. And this time you actually in answer to the second question, did attempt to quantify an answer in the direct testimony itself, correct?
A. Yes, in the initial -- yes, in the DEP initial direct testimony, I have the process in our quantification of the amount -- of what amounts would be different if they initiated sooner, that's correct.
Q. Just to make sure, the reason you attempted to quantify those amounts in the Duke Energy Progress testimony, is the same reason you attempted to quantify those amounts in your Duke Energy Carolinas supplemental testimony, is that right?
A. Yes.
Q. And it looks like two of the steps that you followed, were also used in your attempts to quantify in the DEC supplemental testimony, is that correct?
A. Yes. Yes, the removal of the water supply connection cost, and then,

again, the time value of money evaluation are the two that were similar.
Q. And in connection with the time value of money analysis for Duke Energy Progress, you performed that analysis using the same assumption you used in Duke Energy Carolinas, that is, that the activities being conducted today for which cost recovery is sought would be the same as those which would have been conducted at the earlier points in time, is that correct?
A. Yes, generally, yes.
Q. And is the basis of that assumption in the DE Progress case the same as the basis that you articulated this morning for the Duke Energy Carolinas case?
A. I'm not sure I understand what you mean by the basis.
Q. Well, I mean assumption always has some kind of a basis, correct? There is a reason that you make the assumption that you make?
A. Right. Yes, basis or more than

one -- bases, yes.
Q. Okay, bases. All I'm trying to find out is there any different reason that you made the assumption that you made in the Duke Energy Progress case than you did for Duke Energy Carolinas?
A. The times were a little bit different, but the analysis was the same. In other words, the start times were a little bit different.
Q. And then the mechanics that you used in order to calculate the recommended time value of money disallowances for DEP are the same as the mechanics that you used for DEC, is that correct?
A. Yes.
Q. So you started with system cost over the time period that's presented in Ms. Bednarcik's direct testimony, is that right?
A. Yes.
Q. And you made no adjustment to those costs for the North Carolina retail jurisdiction, is that also correct?
A. That is also correct.

Q. You mentioned that the time periods that you used for Duke Energy Progress were different than the time periods that you used for Duke Energy Carolinas, correct?
A. That's correct.
Q. And I guess it looks like judging from your Exhibit No. 6, which are your work papers for the Duke Energy Progress modification, the time periods you picked were 1992, 1996 and 2009, is that correct?
A. That's correct.
Q. Why did you pick those three time periods?
A. I think '92 was when groundwater contamination had been known at several facilities, including Sutton, and I can't recall the other ones. There may have been more than one. I know it's Sutton.
It was several years after there was documented groundwater contamination.
'96 was when the groundwater contamination claims were made to DEP's insurance carriers, and the 2009 time frame was when after several years of

monitoring from the USWAG -- and that's U-S-W-A-G, all capital letters -- groundwater monitoring was done at the DEP facilities.
Q. Mr. Hart, you mentioned that '96 was chosen by you because claims were made to insurance carriers in connection with groundwater contamination.
Was that for DE Progress or what was then known as Carolina Power & Light and/or Progress Energy or was that for Duke Energy Carolinas?
A. No, it was for CP&L I believe. It's in my testimony.
Q. So your testimony is that CP&L made an insurance or put insurance carriers on notice with respect to potential groundwater contamination in the 1996 time frame?
A. Yes. Yes.
Q. Where is that in your testimony?
A. It's on page 78, starting on line 19.
Q. And you reference on line 19, Exhibit No.'s 34 and 35, correct?

A. Yes.
Q. And Exhibit No.'s 34 and 35 are dated in 2011, right?
THE COURT REPORTER: I'm sorry, I didn't hear the date.
MR. MEHTA: 2011.
THE WITNESS: Well, that's -- I don't know. Off the top of my head it appears that way through, but there were documents I reviewed that I included in my document request that were from the '96 time frame. I'm sure there were.
BY MR. MEHTA:
Q. Going back to the time value of money methodology, Mr. Hart, are the mechanics of the calculation that you made with respect to each of the time periods '92, '96 and 2009, again, the same?
A. You mean the same as DEC?
Q. Well, okay, they are the same as DEC?
A. Oh, I understand. Yes, they are the same for each of them, I'm sorry. I didn't understand your question, but now I do.

Q. Sorry. Each of them is essentially identical, so we can, again, just use one as an example as opposed to going through all three, is that right?
A. That's correct, yes.
Q. And I think you just said that the manner in which the calculations were made are essentially the same as for DEC? Did I hear that correctly?
A. That's correct.
Q. So, for example, if we turn to Exhibit No. 6, and the tab that's titled Step C, there is a figure in cell E7 for the 1992 calculation of $125,000,000, correct?
A. Hold on. I think I actually inadvertently took my Exhibit No. 6 to my office when we broke for lunch. Can I just run and go get it real quick?
Q. Sure.
A. Sorry about that. Okay, sorry about that.
Q. The question essentially was, there is a figure in cell E7 which you may not be able to see if you don't have the

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native Excel spreadsheet of $125,000,000 related to the start year of 1992. Do you see that?

A. You're on like I guess page two of the spreadsheet?

Q. It would be the tab that's called step C, so probably the second page of the spreadsheet?

A. Yes, yeah, okay. Yeah. Right, 125,000,000.

Q. Okay. And my question I guess is, did you calculate that 125,000,000 in the same way that you calculated a comparable DEC figure, which was $171,500,000?

A. Yes. Yeah, using future value calculation in a trial and error to get close to the non-excluded cost from steps A and B.

Q. And the non-excluded costs from steps A and B equals -- or let's see, it looks like 215,000 -- or excuse me, $215,876,818.34. Did I get that right?

A. Yes, that's correct.

Q. And, again, you future valued that $125,000,000 to 2014, correct?

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A. Correct.

Q. And in coming up to your trial and error method with the $125,000,000, you discounted back from 2014, is that correct?

A. No, I forward calculated from 125,000,000 in 1992 to 215,000,000 approximately in 2014.

Q. Did you kind of guess around $125,000,000, and then future value to see whether you were close?

A. Yeah, I mean I just started plugging in numbers until the calculated amount, which is in the cell -- I don't know which cell -- to the right of 125,000,000, was approximately equal to the non-excluded cost from step A and B of roughly $215,000,000 to $216,000,000.

Q. All right. And then the -- that amount, which is cell F7, is $215,679,573.34, correct?

A. Correct.

Q. And the amount immediately below that, which in the native Excel spreadsheet would be cell F8 of

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$90,679,573.34 is the -- is the amount that you recommend should be excluded from present costs, correct?

A. In step C of my calculation, yeah, not the entire amount.

Q. Correct, I understand. With respect to the time value of money calculation, that is the amount that you recommend be excluded from present day costs that Duke Energy Progress is seeking to recover in its rate case, correct?

A. Correct.

Q. And as with your testimony this morning for the DEC supplemental testimony, you are not relying on any standard text or peer reviewed articles with respect to this application of the time value of money method, correct?

A. Well, again, it's just subtracting the $215,769,573.34 from the 125,000,000 which is the difference between the present day cost and the same cost 23 years earlier assuming the time value of money.

Q. And assuming the time value of

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money, you testify it's your opinion that the difference is that $90,679,573.34, correct?

A. Correct.

Q. Flip over, if you would, Mr. Hart, to page nine of your Duke Energy Progress direct testimony.

A. Okay.

Q. And I'm beginning at -- there is a bullet -- I guess it's the third bullet on the page beginning at line five. Actually let me just ask you about the first two bullets.

The first two bullets are generally similar to comparable bullets that you had in your Duke Energy Carolinas testimony, correct?

A. I think the first bullet is -- the first bullet on page nine I don't believe is in the DEC testimony, specifically.

Now I mean there is certainly discussions to that effect, but that bullet I don't believe is in the DEC testimony.

Q. Understood, yeah. I guess what

I'm -- I do recall you testifying about it maybe at your deposition, so maybe that's why I thought it was in the pre-filed testimony.

But as a general proposition, there is no -- the things that we talked about in your deposition that relates to those two bullets for DEC also relates to these two bullets for DEP, correct?

A. Yes, I would agree with that.

Q. Just trying to save some time here rather than go through everything all over again.

A. I appreciate that. Yes, I understand. I just want to make it clear that that bullet wasn't -- some of these bullets were very similar if not the same in the DEP testimony as they were in the DEC testimony.

But just clarifying that that particular bullet I believe probably came out of some of the discussions we had during the deposition was a different bullet. It wasn't exactly the same.

Q. Then skipping then to the third bullet beginning on line five, you indicate that by the late 1980s, as a result of groundwater contamination at the Sutton plant -- you say Sutton facility.

Is there specific parts of the facility that are the focus of your testimony there?

A. Well, I think generally facility and plant I use interchangeably. Certainly the area where the groundwater contamination issues were identified is in the areas of the plant in the coal ash basins, excuse me -- well, and lay of land area.

Q. Well, was there concern by anybody, but particularly DEQ -- I know they weren't called DEQ back then, but for ease of reference, I'm going to call them DEQ.

Was there particular concern by DEQ about areas of the plant other than the coal ash basin?

MS. TOWNSEND: Objection as to form.

THE WITNESS: I believe they also had concerns with the cooling pond.

BY MR. MEHTA:

Q. And is it your testimony that the groundwater contamination -- when you say "groundwater contamination," what was it contaminated with?

A. I mean what time frame are you talking about?

Q. Well, the time frame in your bullet is the late 1980s as a result of groundwater contamination concerns at the Sutton facility. So that's what I'm talking about, too.

A. Okay. I think primarily the concerns were chloride, total dissolved solids or TDS.

There might have been an arsenic concern at that time as well were the primary concern. There may have been others.

Q. And you indicate that DEQ had "significant concern about the presence of groundwater contamination from coal ash basins." Do you see that?

A. Yes.

Q. How do you know that they had significant concerns at that time frame?

A. That was in their documents, DEQ documents that referenced -- I think the reference later on in my testimony specific to that facility.

Q. Is that your Exhibit No. 24B?

A. I don't know off the top of my head. Let me check. Yeah, there is a number of documents in 24B, right.

Q. Is there some document in that group of documents that indicate that DEQ had significant concerns?

A. I believe there is a 1984 memo that said they had "very significant concerns regarding the impact on groundwater quality from the old ash basin and the proposed modifications to the old ash basin."

Q. Which document are you referring to within the universe of 24B?

A. I have to check. It's a May 1984 memorandum, DEQ -- what is now DEQ memorandum.

Q. Does it have -- are you looking at it? Does it have some kind of an identifier on it?

A. I'm not. I might be able to -- I might be able to pull it up. You want me to try?

Q. Yeah, sure.

A. I'm sorry. There are 24 exhibits.

Q. Is it a memorandum dated May 14, 1984 from the groundwater section by any chance?

A. I'm checking. It is May 1984.

MS. TOWNSEND: To expedite this, you may want to check if it's okay with you Kiran, there is a page number I can give to help the process.

MR. MEHTA: Sure.

MS. TOWNSEND: Page 39 of that exhibit.

MR. MEHTA: The pages are not numbered, are they, Terri, so you would be looking at like a PDF?

MS. TOWNSEND: Yeah, you are right.

THE WITNESS: No, that's not it.

BY MR. MEHTA:

Q. I mean immediately behind that is a memorandum --

A. Yes, from Art Hagstrom to Perry Nelson -- through Perry Nelson -- I'm sorry, from Bob Cheek to Art Hagstrom.

Q. Right, through Perry Nelson, and the second paragraph says based on data generated by two sources regarding contamination from ash disposal, we have very significant concerns regarding the impact on groundwater quality of the existing 62 acre lagoon.

Is that what you are referring to?

A. Yes.

Q. What did DEQ do with respect to its significant concerns?

A. With regard to what?

Q. With regard to anything. You indicate in your testimony that they had significant concerns. What did they do?

A. Well, they -- they required that they do some groundwater monitoring, and there was some kind of agreement to put in a liner in the new pond, the clay liner in

the new pond, and I don't know -- it sounds like that was some kind of agreement between the adjacent property owner who was raising concerns about the groundwater quality at the Sutton facility, and I believe in order for them not to protest the expansion and creation of -- expansion of the old lagoon and creation of a new lagoon, they agreed to put in a clay liner in the new lagoon.

Q. Is that what you are referring to in number two, in that bullet on page nine that we have been talking about, number two, a bottom liner installed in a new ash basin?

A. Yes.

Q. But did DEQ have Duke Energy Progress or its predecessor named company do anything with respect to the existing lagoon?

A. I mean they wanted to install groundwater monitoring wells.

Q. Were groundwater monitoring wells installed?

A. Yes.

Q. Was monitoring performed?

A. Yes.

Q. And then what happened?

A. Well, that's a good question. They clearly had groundwater contamination beyond the compliance boundary. There was concerns about impact on an offsite property, including an offsite property water supply well.

And it's not clear to me -- let me get this straight. Sutton has a long history --

Q. Sutton had a long history of what?

A. Groundwater contamination issues. In '87 -- so in '87 DEQ issued a notice of non-compliance for the Sutton facility.

Q. You are looking at your testimony?

A. Yes. Page 139, line 19, in 1987 DEQ issued a notice of non-compliance for the Sutton facility based on the 2L exceedances of TDS and chloride at and beyond the compliance boundary.

Q. And were those exceedances related to the ash basin, the cooling pond or some other part of the facility?

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A. The sources of contamination identified by DEQ in the letter were the intake canal, Lake Sutton and the ash pond.

Q. And when you say in the letter, what are you talking about?

A. In the 1987 notice of non-compliance, which is also in Exhibit No. 24B.

Q. Is there a page reference in 24B?

A. I have to find it.

Q. Actually it might be the first page of the exhibit if that's what you are looking at.

A. Yes. It specifically says TDS and chloride beyond the perimeter of compliance of the ash pond, and then it also goes on to say the sources of groundwater pollution at the L.V. Sutton plant include the intake canal, Lake Sutton, the lined ash pond and the unlined ash pond, collectively called the ash pond.

Q. And then what occurred as a result of this notice of non-compliance?

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A. Well, that's where my documents get a little fuzzy, other than EPA did some sort of expanded site inspection in the 1990 time frame.

Q. Did anything happen between 1987 and the 1990 time frame?

A. I mean the documents that I reviewed, I don't recall specifically.

Q. And I understand, Mr. Hart, there are a lot of documents to review. You did not, I assume, review every single document in the various databases that you reference in your testimony, did you?

A. I did not. I reviewed for Sutton every document in the DEQ's Laserfiche regarding this facility.

Q. I'm sorry, when you say DEQ Laserfiche, what is it that you are talking about?

A. So that's DEQ's online document repository for various programs, and we looked at the division of water quality file and the division of waste management files.

Q. Are those repositories intended to

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be complete by DEQ?

A. I would say they are the most complete public regard there is.

Q. With respect to that clay bottom liner installed in the new ash basin, if a clay liner was to have been retrofit into the old ash basin in 1992, do you think that would have been a sufficient remediation?

A. Sufficient for what?

Q. To address groundwater contamination allegedly caused by the old ash basin?

A. If it was properly engineered and properly constructed, potentially, yes.

Q. What does potentially, yes, mean, Mr. Hart?

A. Well, if it was -- I can't say if you just stuck six images of clay in the bottom that would work, but if you had a properly engineered low permeability that met specific specifications for a permeability liner that was installed, it's certainly possible, yes -- well, it could have stopped further groundwater

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contamination, but there was certainly already groundwater contamination around the pond or associated with the pond.

Q. But would it have been an appropriate method of source control in 1992 to retrofit the existing pond or the old pond with a clay liner, a properly engineered, properly designed clay liner?

A. I mean it is -- yeah, it would have been appropriate to do that.

Q. Would it have been appropriate in '96?

A. Yes, I think so. Yes.

Q. Would it have been appropriate in 2009?

A. Possibly.

Q. Why are you hesitating when you say possibly?

A. Well, some of these basins were out of service by then, so I don't -- it's possible it wouldn't have -- like this basin I believe was out of service before 2009. It wouldn't make much sense to pull out -- if they wanted to reuse it, it would make sense, but it wouldn't make

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sense to pull out the ash, put in a clay liner and then put the ash back in. Potentially it may, I don't know.

It was essentially full by some point before 2009.

Q. Well, should one of the unlined ash ponds at some of Duke Energy Progress' other plants have been retrofit -- would it have been appropriate to have them retrofit with a clay liner in 1996?

A. I mean, do you have specific examples? I think each one represents a unique situation.

Q. Is there any that you can think of that would have benefited from a clay liner installed in 1996?

A. Not off the top of my head. It's possible that there were some, yes.

Q. How about in 2009?

A. Again, it's possible there were some.

Q. So your testimony is it would have been appropriate for Duke Energy Progress to retrofit its existing and in use ash basins in 2009 with a clay liner?

MS. TOWNSEND: Objection.

THE WITNESS: No. What I said was it was a possible means of mitigating future groundwater impacts. It's not the only means of doing it, but it is a possible means. It certainly would have been a good practice depending on which site it was, and what the circumstances were. But I didn't -- go ahead.

BY MR. MEHTA:

Q. Would you have recommended it in 2009 for any in use ash pond with Duke Energy Progress?

MS. TOWNSEND: Objection as to form.

THE WITNESS: I didn't make an evaluation of that.

BY MR. MEHTA:

Q. So you have no opinion of that sitting here today?

A. Not a specific pond. It certainly was a potential reasonable alternative to address groundwater contamination.

Q. Let me make sure I understand. It is your testimony that a retrofitted clay

liner was a reasonable alternative to groundwater contamination for mitigating groundwater contamination or preventing further groundwater contamination in 2009?

A. Yes, I believe so. Yes.

Q. In that bullet on page nine that we have been discussing, you indicate that DEP was also aware of number three, the concentrations of compounds in groundwater were elevated from a coal ash pond that did not exceed the groundwater standards. They were still a concern to DEQ and needed to be evaluated further. Do you see that?

A. Yes.

Q. Is your source again some document in Exhibit No. 24B?

A. Yes.

Q. Can you point me to your source?

A. I will try. That would be page 20. It's in April, and it's crossed out, 30, 1986 letter from what is now DEQ to Mr. R.B. Starkey, manager of nuclear safety and environmental services.

Q. Where?

A. On number two it says it is probable that the sources have resulted in an increase in the concentrates of chloride and TDS that is 50 percent of the GA standard for chloride.

In other words, it didn't have to exceed the standard in order for it to be of concern. So based on these findings, the letter says, you must submit a plan that will accomplish the following.

Demonstrate that the sources are not contravening GA standards established for chloride and TDS, and demonstrate that the sources will not adversely impact potable water derived from the New Hanover County water system.

You are referred to 15 NCAC 2L .0202(a), which explains the basis for requiring this.

Q. Was what the DEQ -- or done?

A. As far as I can tell in that time frame, it appears that way when they installed the well, even though, again, the documentation is a little spotty of DEQ files.

Q. Did you obtain the Exhibit No. 24B from the microfiche repository that you were talking about?
A. Yes.
Q. Mr. Hart, I have seen, and maybe it's in some of the documents that you attached as exhibits, the term BTV, an acronym for something or a set of initials for something, B as in boy, T as in Tom, and V as in Victor. What does that mean?
A. It's a background threshold value.
Q. Background threshold value. How does that relate to determining whether or not there has been an exceedance of groundwater standards?
A. Well, background threshold value is a statistical analysis of data from presumed background wells, and there is a calculation that comes with what they called background threshold value.
It's similar to an upper confidence limit for a normal distribution.
Q. Had background threshold values for constituents of concern been

established at Sutton in the time frame that's covered by this bullet in the late 1980s?
A. I don't -- well, there was no BTV established until -- I don't believe until 2016 or '17 at any of the DEP facilities.
Most of them had some form of background well. Some of them didn't. You don't necessarily have to use a BTV to calculate or to determine background groundwater quality.
Q. Do you need a BTV in order to determine whether there had been an exceedance above background beyond the compliance boundary?
A. No.
Q. Go to the next bullet on page nine, Mr. Hart, begins on line 14.
You say that at the Robinson, Roxboro and Weatherspoon facilities groundwater monitoring had been conducted as early as the early to mid 1990s and indicated groundwater contamination issues with coal ash disposal areas.
When you say "groundwater

contamination issues," what do you mean?
A. Groundwater above the 2L standard could be background if background had been established, if were naturally occurring compounds.
Q. So the groundwater monitoring that was conducted in the time frame of the early to mid 1990s at those three facilities, indicated some elevated levels of compounds that might be due to background? Did I understand you correctly?
A. No, no, no. I was saying if a groundwater contamination issue is a detection above the 2L standard, or it could be also if it were a naturally occurring compound, it could be a detection above background if an established background level was higher than the 2L standard.
Q. Well, in the context of this bullet, what do you mean by groundwater contamination issues in the early to mid 1990s at those three facilities?
A. Just that. Just what I said.

Q. Well, does that mean that there were levels in excess of the 2L standards not attributable to background beyond the compliance boundary?
A. No, it could be within the compliance boundary. I think Robinson is in South Carolina, so it would be the MCO anywhere at Robinson.
Q. True, Robinson would not have anything to do with 2L standards, but it would have some standard, correct?
A. Right.
Q. What I'm trying to get at, Mr. Hart, is you used the term groundwater contamination issues.
You do not use the term an exceedance that is a violation of the 2L or whatever the comparable South Carolina standard is, and I wondered if that was on purpose or whether your language was loose or what?
A. Well, my language wasn't loose. All I'm saying is a groundwater contamination issue is something above a standard or if the background is above the

standard above background. It did not take into account compliance boundaries to the extent that they are applicable.
Q. Were they applicable?
A. With Robinson, no. Roxboro and Weatherspoon potentially, but I believe Roxboro had groundwater contamination in the bedrock which, of course, the compliance boundary does not apply to. I would have to check.
There was an indication of groundwater contamination that needed to be investigated further. As noted in DEP's correspondence regarding the Sutton -- I mean DEQ's correspondence regarding the Sutton facility that even concentrations that are less than the standard require further evaluation.
Q. What did DEQ do with the information that it was supplied in the early to mid 1990s concerning groundwater contamination issues at Roxboro and Weatherspoon?
A. I don't recall them doing anything specific is my recollection, although, I

would have to go back and check.
Q. What did South -- did DHEC do with respect to the information it was supplied in the early to mid 1990s indicating groundwater contamination issues at Robinson?
A. I would have to check. I don't recall specifically.
Q. I see you looking. It is a little hard when you are not in the same room.
Are you trying to find the answer to that question or are you just flipping around?
A. No, I was trying to find the answer to any specific in our discussions because some of the details regarding facilities are difficult to keep straight.
I don't recall anything specific that DHEC or DEQ requested. DEP -- I guess the question in my mind is what did DEP do in regard to the detection of contamination above standards in regard to the coal ash basins when they got the data.
Q. I assume because there was some

kind of a detection of what you called groundwater contamination issues in the early to mid 1990s that at those facilities groundwater monitoring was taking place in the early to mid 1990s, correct?
A. Yes. Yes.
Q. Did DEQ decide at some point that groundwater monitoring should cease at either of the two North Carolina facilities after the early to mid 1990s?
A. I don't recall seeing any specific correspondence regarding that.
Q. So you don't know one way or the other?
A. I would have to check each site individually to see when they were actually doing groundwater contamination and whether the groundwater contamination continued or whether there is a period of stoppage.
I don't recall any specifics regarding DEQ saying you don't have to take samples anymore around a basin that has groundwater contamination issues.

Q. Every single one of these facilities, Mr. Hart -- by facilities I guess I mean the coal ash basins, required an NPDES permit, correct?
A. Yes, yes. At some time, yes.
Q. And those permits don't last forever, do they?
A. No, they do not.
Q. They are periodically reviewed and renewed by the applicable environmental agency, correct, DHEC in South Carolina, DEQ in North Carolina?
A. Yes, they have to review the applications -- in order to renew an application, the party has to submit a renewal application, I believe it's 180 days ahead of the expiration date, that includes the reapplication for the discharge permit.
Q. And based on your review, the DEP, if it wanted to renew a permit, submitted an application for renewal within that 180 day or upside of 180 day deadline so that it was timely received by the applicable environmental agency, is that correct?

A. I'm sorry, you broke up a little bit. Can you repeat that?
Q. Sure. In any instance in which DEP wanted to renew a NPDES discharge permit, it submitted a timely application for renewal which was then processed by the applicable environmental agency, is that correct?
A. They would review the materials that were submitted to them in the application, as well as some compliance monitoring potentially. Certainly there was no mention of groundwater contamination that I saw in the DEP applications after the detection of groundwater contamination as part of the application.
Q. Are you saying that the environmental agency in question, either DHEC in South Carolina or DEQ in North Carolina, was unaware of the results of whatever monitoring had taken place before the renewal application was submitted?
A. I don't know. We have tried to get both DEQ and DEP -- I'm sorry, DEQ and

DHEC files to determine what was submitted to them.
Unfortunately there is a pandemic going on and they were unwilling to go get the files for us related to what was in their files that had been submitted to them by DEP.
Q. Do you have any reason to believe, Mr. Hart, that whatever the results of the monitoring were, they were not submitted to the applicable environmental enforcement agency, either DHEC in South Carolina or DEQ in North Carolina?
A. I don't have any information that they were either submitted or not submitted based upon the documents that I reviewed.
Q. Well, have you ever seen a document from DEQ in North Carolina or DHEC in South Carolina, indicating that it had not received monitoring data from DEP?
A. I don't know. There could have been some of NPDES permit issues with regard to reporting on NPDES outfall.
I didn't really focus on that, but

I feel like there were some NOVs issued for missing some things.
THE COURT REPORTER: I'm sorry, you broke up a little bit. I didn't really focus on --
THE WITNESS: I think -- the surface water non-compliance issues, but I believe there were some instances where some NOVs or notices of violation were issued for not submitting some information.
BY MR. MEHTA:
Q. For surface water purposes, correct?
A. Yes.
Q. Have you ever seen a complaint from anybody, DEQ or DHEC, that indicated to you that DEQ or DHEC thought that Duke Energy Progress had withheld any groundwater monitoring data that was generated at a Duke Energy Progress coal ash basin?
A. Not that I can recall. I would have to check the Sutton fine.
Q. The Sutton fine meaning --

A. The $26,000,000 fine for the Sutton facility for groundwater impact.
Q. You think that in the $26,000,000 or $25,000,000 fine for the Sutton groundwater impact, which was a claim by DEQ, correct? Nobody paid them $25,000,000, did they?
A. My understanding is the fine was reduced, yes.
Q. In connection with that claim, is it your testimony that DEQ made any complaint that information concerning groundwater monitoring had been withheld by DEP?
A. I said I would have to review it to be sure. That's the only place I could think it would be and I said simply I don't recall it being there.
THE VIDEOGRAPHER: Mr. Mehta, we need to take a break to change the video and give Andrea a five minute break.
MR. MEHTA: Okay. Why don't we -- let's see it is 1:45. We have been going basically an hour and a quarter. Why don't we take five minutes, ten minutes.

THE VIDEOGRAPHER: We are going off the record at 1:41 p.m. This is the end of media number three.
(Recess was taken from 1:41 p.m. to 1:57 p.m.)
THE VIDEOGRAPHER: We are back on the record at 1:57 p.m. This is the beginning of media number four.
BY MR. MEHTA:
Q. Mr. Hart, if you would skip over to page ten of Exhibit No. 4, to the bullet that starts on line ten.
A. Okay.
Q. And in this bullet you are talking about the USWAG, that's all caps, U-S-W-A-G, for voluntary monitoring plan, correct?
A. Correct.
Q. And you indicate -- just paraphrasing, you correct me if I'm wrong, you indicate that the USWAG plan calls for utilities to work with regulatory agencies to further assess conditions and as needed to develop corrected action plans. Does that basically capture what you are

saying?
A. Yes.
Q. Is it your testimony that Duke Energy Progress did not do that?
A. Well, the USWAG action plan indicated that upon detection of groundwater impacts above a regulatory level and properly identified background concentrations, after some period of evaluation, then the regulated utilities or the utilities that were part of the USWAG action plan, and I believe it was within 90 days were supposed to contact the agency to further assess conditions and as needed develop corrective action programs.
Q. Is it your testimony that Duke Energy Progress did not communicate with the regulatory agencies in question, and in particular with DEQ, to further assess conditions and as needed develop corrective action plans?
A. Yes, not until DEQ requested them, DEP to further assess conditions in 2010, I believe it was, and then certainly no

corrective action plans were developed except for the L.V. Sutton facility, which had a proposed corrective action plan for the lay of land area which was submitted under the REC program, which was never implemented because it wasn't concurred by DEQ.
They did not do any corrective action plans until CAMA, after CAMA, C-A-M-A, all caps.
Q. Are you familiar with Colleen Sullins, S-u-l-l-i-n-s?
A. Yes. Well, somewhat. I have seen her name on documents.
Q. Did you ever interact with her when she was at DEQ, whichever division of DEQ it was?
A. I don't know if I directly interacted with her or not. She certainly -- her name was on correspondence that I had reviewed or clients received.
Q. She was actually I guess the director in this time frame when the USWAG monitoring was going on of the division of

water quality, correct?
A. I am aware that she was fairly high up in the division of water quality, but I don't know her specific title or what time frame it was.
Q. In terms of the manner in which DEQ was organized, the division of water quality would have been the division in charge of groundwater monitoring, correct?
A. I would say for permitted facilities, yes, but I think there were certainly some non-permitted older ash stations in the lay of land area that did not fall under division of water quality at that time.
Q. It fell under some other division of whatever DEQ was called at the time, correct?
A. Yes.
Q. Maybe waste management?
A. Correct.
Q. But in terms of the ponds themselves and certainly ponds that were permitted with an NPDES permit under the NPDES program that would have been a

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division of water quality responsibility, correct?

A. Yes, that's my understanding.

Q. Do you know what Robin Smith's role was during this period of the USWAG voluntary action plan?

A. Not off the top of my head, no.

Q. Was she the assistant secretary of the Department of Environmental and Natural Resources, which was what DEQ was called at the time?

A. She could have been. I don't recall what her specific title was.

Q. Do you know that she was high up in the hierarchy of the department?

A. I think she worked her way up. She wasn't always high up in the department, as I recall, but as some point she was fairly high up, yes.

Q. Did she enter the department as the assistant secretary back in 1999?

A. I really don't know her past. If you have something to show me, I would be glad to look at her CV or something like that.

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Q. In the course of your investigation of basically these two matters, both the DEC rate case and the DEP rate case, did you talk to either Ms. Sullins or Ms. Smith to try to get an understanding of what was happening at the DEQ during the time period of the mid to late 2000s?

A. I did not talk to either one of them. I reviewed the correspondence that's in the file with regard to that issue, which indicated that DEQ had reviewed -- in 2010 was responding to the data that had been received from DEP with regard to the USWAG, and wanted additional information.

Q. Wasn't that in 2009, not 2010?

A. Yeah, I think the original letters were in 2009. I think you are right, yes.

Q. March of 2009 perhaps?

A. I would have to check. I don't recall.

Q. Is there some reason that you didn't seek to interview or reach out to or find information from people who were

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at DEQ in this time period if you thought it was a relevant time period to understand what was happening within DEQ?

A. No. I mean I wasn't around during that time period. I don't know. I think Robin Smith left public office, but it's not something I would track somebody down like that.

It was clear from the USWAG action plan what utilities were supposed to do. They were supposed to contact DEQ and come up with a plan for further -- to further assess conditions, and as needed develop corrective action programs, and they were supposed to do that in a specific time frame. There is no indication that was done.

Q. Do you know the form of the data that was submitted by DEP to DEQ in connection with the voluntary action monitoring plan?

A. Not for DEP. Again, we tried to get that information and DEQ indicated that they didn't have anyone that could retrieve it. We did get some of that

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information for DEC.

Q. When did you ask for it for DEP Progress?

A. I believe in February sometime.

Q. When did you ask for it for DEC?

A. Probably in December of 2019.

Q. Why didn't you ask for it for DEP at the same time?

A. Because we had not been retained to work on the DEP case at that time.

Q. So you were retained separately for DEC and DEP?

A. Yes.

Q. When were you retained for DEP?

A. I would say within a week after my deposition. So maybe it was March. Within the first two weeks of March, I believe.

So it may have not been until March that we requested -- I have to go back and check.

We did provide that in a response to DEP's request two, I believe.

Q. You supplied what in response to DEP's request two?

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A. Any correspondence we have with DEQ regarding trying to get their files.

Q. Mr. Hart, in connection with your investigation of this matter, did you come to understand the impact, if any, that the TVA, T as in Tom, V as in Victor, A as in alpha, all caps, coal ash spill had with respect to any of the issues involving groundwater monitoring in DEP's coal ash ponds?

A. I don't recall seeing much at all about the TVA's spill. That was a dam failure, so it wasn't really necessarily related to groundwater contamination.

Most of the documents that I looked at with regard to DEQ referenced the 2014 Dan River spill that Duke Energy had.

Now, certainly in some of the -- like the CCR rules, in the preamble, there is some discussion obviously of the TVA release.

Q. Did you come to understand or find that the TVA spill had any impact on DEQ's attitude towards coal ash?

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A. I mean I certainly think there was some concern related to that. Obviously they are typically discussed in the same kind -- as I mentioned in the previous deposition, it's kind of dull weather moments in coal ash basin issues, both the TVA spill and the Dan River release.

So I'm sure they had some indication or implication to DEQ. I think the one that certainly was the main impetus to the CAMA rules was from my reading was the Dan River spill.

Q. But you haven't reached out to anybody at DEQ or what would have been DEQ at the time, to see if the TVA spill had any impact on DEQ's attitude or its coal ash basins, had you?

A. No, I haven't reached out to anybody specifically, no.

Q. If you would -- you mentioned the CCR rule, that's again all caps, C-C-R. The initial proposed CCR rule was within a few months of the TVA spill, was it not?

Well, actually probably a little over a year after the TVA spill, correct?

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A. Well, the TVA spill, I don't know exactly what month. I think it was in 2008. I think that's the proposed rules was in 2010. That's two years or a year and a half. I'm not exactly sure.

Q. I think TVA was December. If I have my years wrong, you can ignore that question.

Mr. Hart, in the period of the USWAG voluntary action monitoring program, do you think that DEQ was simply turning a blind eye to whatever data was being submitted by Duke Energy Progress, groundwater monitoring data that is?

A. I don't think blind eye is right. I think it's just an understaffed agency typically that -- and the main focus of the NPDES program is surface water discharge.

And so that's their primary focus, writing permits and ensuring compliance with surface water.

I don't think they were probably until somebody noticed in 2009 that we have been getting all this data, let's

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look at it.

That would be my best estimate of what happened based upon my experience with DEQ in the past.

Q. That's a guess, isn't it?

A. It's not a guess. I think it's pretty good -- I think based upon the correspondence and based upon my experience, it's probably more very likely that's what happened.

Q. Had you spoken with anybody at DEQ to confirm your supposition that that was likely what happened?

A. No. It's pretty clear in the correspondence that when they send out these notices in 2009 that says we have been getting all this data from you, we need more information. Where are these wells? Where are the compliance boundaries? Where are the background wells? Which wells are background?

It's just data that was being submitted.

Q. Go on, if you would, to page 12 of Exhibit No. 4. You have a bullet that

begins on line six.
A. Yes.
Q. And you indicate in this bullet that there was some uncertainty about how coal ash ponds would be managed prior to the enactment of CAMA and the promulgation of the Federal CCR rules. Do you see that?
A. Yes.
Q. What was the nature of the uncertainty that you had acknowledged in that bullet?
A. I think there was some uncertainty about what the closure process would look like for basins, time frames. One of them certainly was the hazardous, non-hazardous waste issue, although I think if you read most documents, and before CCR's rules certainly indicated that in all likelihood it was not going to be considered a hazardous waste.
Q. If it was in all likelihood not going to be considered a hazardous waste, why did EPA propose as one of its alternatives in its CCR rules in 2010 that

it might be considered as a hazardous waste?
A. I mean the main reason was to receive public feedback.
Q. Well, there are other things that EPA proposed in 2010, among them that it wouldn't do anything at all. Was that also likely in your view, Mr. Hart?
A. No, that wasn't likely.
Q. How do you say that one was likely and what one was not likely if they are both in the proposed rule?
A. I think certainly the feedback that the agency had been getting was being fed out to the, you know, regulated communities and engineers, and that kind of thing and it indicated this was not going to be a do nothing, nor does it look like this was almost certainly not going to be a hazardous waste issue.
There was a good amount of knowledge about what was going to happen before the actual CCR rules came out.
Q. You mentioned also that one of the forces of uncertainty was how to close a

basin, correct?
A. Just the options I guess, that was one thing, and would there be different requirements potentially for basins, whether there was groundwater contamination or not, that kind of thing.
Q. What are the options that were available?
A. In what time frame are you talking about?
Q. Well, I guess whatever time frame you're talking about in your bullet on page 12 starting at line six, which as I understand it, just given its placement, is kind of in the same USWAG, you know, mid to late '90s time frame, but I could be wrong. That was just my interpretation.
A. Well, USWAG wasn't until 2006.
Q. Well, that would be the mid 2000s. Did I say 1990s? I meant 2000s?
A. Yes.
Q. Mid to late 2000s?
A. Yeah. I think what I'm talking about is this time period between 2010 and

when the CCR rules in CAMA came out, which is 2014, and there was certainly methods to deal with coal ash basins. You excavate them out, close them in place, do some kind of hybrid closure.
Q. Was there any regulated utility in the 2010 to 2014 time frame that was closing ash basins?
A. I'm pretty sure that Duke -- it may not have been Duke at the time, but one of the facilities over in Ohio or Indiana closed out a basin and installed a new lined basin.
Q. Was there any regulated utility in the southeast in the 2010 to 2014 time frame that closed an ash basin?
A. I don't know. The rules in North Carolina are different than the rules in other southeastern states.
We have 2L groundwater standards that specifically dictate how you are supposed to address groundwater contamination.
Other states might not have those rules, and in fact, a lot of them don't.

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Q. Mr. Hart, we'll get to the 2L rules. I'm still focused on the uncertainty that you acknowledge about how coal ash ponds would be managed prior to the enactment of CAMA, and the promulgation of the Federal CCR rules?
MS. TOWNSEND: Objection.
BY MR. MEHTA:
Q. You indicated that part of the uncertainty was that there were a number of different options on how to close a basin. Did I get that right?
A. Yes. What I'm saying -- I think you are taking a sentence out of context. I'm saying although there was some uncertainty, in North Carolina it was different. There was no uncertainty about the 2L rules. There is some uncertainty about the CCR rules, because CAMA really wasn't the focus before the Dan River spill.
But there was no uncertainty as far back as 2009 about what the 2L rules required.
Q. There was some proposed

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legislation in North Carolina that predated CAMA, did it not, that dealt with coal ash basins?
A. Yes, right. There was closure of those basins.
Q. I'm sorry, you broke up on me there. Did you say that that proposed legislation dealt with closure of the basins?
A. Well, as I recall, it was going to require closure of the basins, yes.
Q. And that proposed legislation was not passed, correct?
A. That's correct, not specifically, no. It was kind of a precursor to the CAMA rules.
Q. What you are saying, as I understand it, now that you clarified it, Mr. Hart, that although there was some uncertainty pre-CAMA, pre-CCR rules about coal ash ponds, you state there was no ambiguity about the requirements of the 2L rules, correct?
A. Correct, what the requirements were to address groundwater contamination.

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Q. Did the 2L rules require the closure of a coal ash basin?
A. No. They required that the source of the contamination be mitigated and controlled.
Q. Which is what you say essentially in the rest of the bullet, correct?
A. Yes.
Q. That the 2L rule require a responsible party determine the nature and extent of the contamination, terminate and control the discharge, mitigate -- perform receptor surveys, and propose and implemented corrective action, correct?
A. Correct.
Q. And it is your testimony, Mr. Hart, that the 2L rules were unambiguous with respect to Duke Energy Progress' coal ash basins in requiring those things?
A. In my experience, yes, 2L rules override many other regulatory programs.
Q. And those rules that override other programs, come into play when exceedances of the standards are detected beyond the compliance boundary and are

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shown to have been caused by the facility in question, is that correct?
A. In North Carolina for permitted discharges assuming it's not in the bedrock aquifer.
THE COURT REPORTER: I'm sorry, bedrock --
THE WITNESS: Aquifer.
BY MR. MEHTA:
Q. Mr. Hart, you indicate or you think that there is no ambiguity, but didn't the materials you yourself reviewed indicate that DEQ had some question about the applicability of the 2L corrective action rules to Duke Energy Progress' coal ash basin?
A. No, I don't remember saying that.
Q. Well, on page -- if you would flip over to page 35 of your testimony, you reference starting at line ten a letter issued by DEQ dated December 18, 2009 that is Exhibit No. 11 to your testimony. Do you see that?
A. Yes.
Q. And you indicate starting on line

12 that the letter based on a clarification from the Attorney General's office, indicates that facilities permitted prior to December 30, 1983 that had exceedances are subject to the corrective action provisions of the 2L rules, correct?

A. Correct.

Q. And the Attorney General's office is your client in this matter, correct?

A. Right. My understanding is this and the subsequent correspondence was there was a question about where did they have to meet the standard? Was it at the compliance boundary or adjacent? Did the compliance boundary apply?

Q. Well, did your client, the Attorney General's office, supply you with any information at all about this clarification?

A. No.

Q. Did you ask for any clarification or information about this clarification?

A. No, I don't believe so, no, not --

Q. Do you have your Exhibit No. 11

handy, Mr. Hart?

A. No.

Q. I think actually we might be able to see it, because I believe Meredith can show it to us somehow on the screen if you don't.

In looking at it, the second paragraph of this letter, December 18, 2009 letter, says during this review period and they are referring to a review period over the past several months, the first paragraph, during this review period there has been a clarification by the Attorney General's office of how corrective action requirements apply to facilities permitted prior to December 30, 1983. Do you see that?

A. Yes, I see that.

Q. So I take it there was some question that the DEQ had, as to how the corrective action requirements would apply to facilities permitted prior to December 30, 1983, is that right?

A. I don't think so. I think there is a question that DEP raised about

whether they could seek a corrective action plan by natural attenuation processing.

In other words, could they follow .0106 L or K or did they have to follow .0106 G.

Q. Well, is that not a question that the agency itself had from whatever source it got it as to how the corrective action requirements would apply to facilities such as every single one of the coal ash basins permitted prior to December 30, 1983?

A. This is addressing, in my opinion, whether DEP can seek corrective action under the processes of natural attenuation without going to the groundwater standards or whether they have to meet the groundwater standards. They still have issues with groundwater --

THE COURT REPORTER: I'm sorry.

THE VIDEOGRAPHER: Timeout.

THE COURT REPORTER: The witness -- you were both talking at the same time. I just didn't get the end of

his answer. That's all.

BY MR. MEHTA:

Q. Try that one again, Mr. Hart, I'm sorry. And actually, I think, Meredith, we can take down the -- thanks.

A. This is a question about whether DEP could use processes of natural attenuation for the groundwater contamination, or whether they needed to clean up in accordance with .0106, I don't know if it's C or G. I don't remember.

So it's important from when you submit your corrective action plan, but it's not important in terms of do I need to do further assessment? Do I need to stop the source of the contamination?

You can't get a natural attenuation corrective action plan unless you stop the source of the impact.

Q. Mr. Hart --

A. Do I have suffer impacts, have I receptor evaluation, all the things that's required in .0106 L for a natural attenuation corrective action plan have to be met first.

Q. But is there any point in doing -- if your point is to try to achieve a natural attenuation plan, if that was the point, isn't it important to understand from the regulated entity's standpoint that that says an available option?

A. It's important before you submit your corrective action plan, but it's not important -- it does make a difference in point because whatever provision you were under, .0106 L or .0106 B, whether you still have to stop the source and control it, whether there are receptors in the area, what the background concentrations are, what the vertical and horizontal extent of contamination is, all those have to be determined no matter what method of .0106 you determine you might be able to fall under.

Q. So are you saying, Mr. Hart, that whatever clarification was sought by the DEQ to the Attorney General's office, it made no difference to DEP and the manner in which DEP moved forward with the work that was being done with respect to

groundwater contamination at the coal ash ponds?

A. And that's not what I said. What I said was there are certain steps that no matter what what impact has been taken to address whether or not you could get .0106 L, you still had to do all the things to find the vertical and horizontal extent of contamination and mitigate the source of the contamination.

All those things still had to be done, receptor evaluation, no matter what. So there was no reason to delay doing them just based upon an evaluation of whether you could get a .0106 L corrective action plan approved sometime in the distant future.

It's not just, hey, we are going to go do it. I'm just going to go submit under this. You have to go through all the protocols for any corrective action plan.

THE COURT REPORTER: I'm sorry, this is the court reporter. I just need the witness to slow down for me just a

little bit.

BY MR. MEHTA:

Q. Mr. Hart, what is the source of your information that this clarification that is described as a clarification regarding how corrective action requirements apply to facilities prior to December 30, 1983, is solely concerning remediation -- or a corrective action plan that does not require remediation to groundwater standards or may allow attenuation by natural causes?

A. That's what the letter says, and that's my experience in North Carolina.

There was some uncertainty with when the provisions to the 2L rule came out to allow corrective action to alternate standards about the application of that.

Q. And again, is that something that you consulted with your client, the Attorney General's office about?

A. No. I have been a hydrogeologist in North Carolina for 30 years. I have seen letters like that, a lot of letters

similar to that.

Q. Still on page 35 of your testimony, Mr. Hart, beginning at line 19, you indicate that on June 17, 2011, DEQ issued a "policy for compliance evaluation of long term permitted facilities with no prior groundwater monitoring requirements," which is part of Exhibit No. 12, correct?

A. Yes.

Q. Now when DEQ issues a policy statement, it does so in order to provide clarity and guidance and in order to assure consistency, isn't that correct?

A. I would say in general, yes, although policy is not a substitute for the regulations themselves.

Q. Well, if there is any confusion within the agency or within various divisions of an agency as to what the requirements of the rules are, one way to solve that confusion, is the issuance of a policy statement that lays out how the rules are to be applied, is that not correct?

A. I think in general terms, yes, although a policy that hasn't gone through the full rule making process, is by no means a rule.
Q. And this is not described as a rule, is it? It's described as a policy?
A. Correct, I agree.
Q. And so it is as a policy something to guide the agency itself, and also to provide clarity and consistency with how the agency deals with the regulated community that the agency regulates, correct?
A. Yeah, I would say in general terms, yes.
Q. And on page 37 of your testimony, you set forth the flowchart that describes how the policy is to be implemented, correct?
A. Correct. Well, yes, the policy. It really doesn't describe how it's going to be implemented. It's just a flowchart for the policy.
Q. Well, it's a flowchart that describes how the agency and the regulated

entities are supposed to interact as they move through the process of assessment to corrective action for groundwater monitoring, compliance and remediation, correct?
A. Yes, or violation. Yes.
Q. It would lead to some kind of enforcement proceeding potentially if the regulated entity acted in a way that contravened the policy, correct?
A. I don't know. It depends on the policy.
Q. Well, this policy. Do you see the box at the bottom left-hand side that says division issue notice -- that's no further action, sorry. The one on the left-hand side in the middle, division issues, notice of violation?
A. Yes.
Q. You see?
A. I see that, yes.
Q. And immediately above that, there is another one that says division issues notice of violation, correct?
A. Yes.

Q. And the lower one, the way you get to the lower one is the diamond immediately to the right of the lower one, correct?
A. Yes.
Q. And in the diamond, it says permittee, which I guess would be the regulated entity, complying with corrective action requirements in accordance with the 2L rules, right?
A. Correct.
Q. And the flowchart reads no. So if the permittee is not complying with the 2L rule corrective action requirements, then the division issues notice of violation, correct?
A. I think you have to read this in the context of the policy itself because it says even though people might not be in compliance with the 2L rules, if they are working towards addressing the issue, we wouldn't necessarily issue a notice of violation.
Q. Well, if they are working towards addressing an issue, then the diamond to

the right of division issues notice of violation would be in the yes direction and not the no direction, correct?
A. No, because the yes says you successfully completed the correction requirements. It says -- you could be in violation of the corrective action or the 2L rules and not have a fully compliant corrective action requirements in the triangle, and it may not issue a notice of violation.
This isn't a requirement to do something.
Q. I understand, but in terms of the way a flowchart works, and I assume you are familiar with flowcharts, correct, Mr. Hart?
A. Yes.
Q. The way the flowchart works, as I understand it, you can correct me if I'm wrong, if the facility is non-compliant, but the permittee is working with the agency to deal with that non-compliance, then the division is certainly not likely to issue a notice of violation, is that

correct?
A. I guess it depends on the time frame. Certainly in some time frames DEQ would issue an NOV if you had a groundwater standard violation, even before you started corrective action requirements, for example, the 1987 notice of violation or its similar equivalent at Sutton.
It really depends on the time frame you're talking about.
Q. Well, the time frame of this policy begins in 2011, does it not?
A. Correct.
Q. And so in that time frame, if the facility is non-compliant, but the permittee is working with the agency to address the non-compliance, the agency is at least not likely to issue a notice of violation, is that correct?
A. You are talking about this -- well, in accordance with this, yes.
Q. Well, in accordance with this, this is the DEQ's policy, right?
A. As of June 17, 2011.

Q. And all the way until this was rescinded somewhere in December 2015, correct?
A. Correct. I think they cited it in the Sutton $25,000,000 fine, too.
Q. Who cited it?
A. DEQ I believe.
Q. Your understanding is that DEQ cited this policy as being applicable in the Sutton $25,000,000 fine proceeding?
A. My recollection is that, yes. I could be wrong. I don't know. That's my recollection, yes.
Q. Isn't it, in fact, true, Mr. Hart, that the DEQ acted as though this policy didn't even exist when it issued the $25,000,000 fine?
A. I don't know that, no. I have seen it referenced in several fines.
Q. But your testimony is as far as you are concerned, the DEQ was trying to enforce this policy in connection with the Sutton $25,000,000 fine?
A. Again, I remember it being referenced in some -- one of the fines.

It may not have been the Sutton $25,000,000 fine. It could have been something else. I would have to look. I don't recall.
Again, a policy is not the regulation, but that's what the policy says, yes.
Q. A policy is designed to have people rely on it, right? I mean it's not much of a policy if it's not published to the people you are trying to influence their behavior and not have them rely on it, isn't that correct?
A. Yes, I agree. I would agree that this is a policy. My experience would be to from this time frame is that if you were working on corrective action, that you would not typically get a notice of violation. I would agree with that.
Q. Go back to page 12 of your testimony, Mr. Hart, and on the very last bullet of that page you reference a letter to Duke Energy Progress' insurance carriers in 2011, correct?
A. That's correct.

Q. And you indicate on line 19 North Carolina is taking aggressive action on coal ash facilities, is that right?
A. I didn't say that. That's what the letter says.
Q. You agree with that, don't you?
A. I would say in the general sense they were starting to take aggressive action, yes.
Q. And you indicate that the lack of ambiguity about the requirements of the 2L rules was confirmed by this letter that was sent to Duke Energy Progress' insurance carriers, right?
A. Correct, that DEP knew about the lack of ambiguity in the 2L rules because they indicating here that the existing regulations already describe the corrective action process, and they also describe the same potential closure schemes as the EPA proposed rules.
In this letter it says that addressing these coal ash basins is inevitable.
Q. The letter that you reference is

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Exhibit No. 34 to your testimony, correct?
   A.   I would have to check. Yes, Exhibit No. 34.
   Q.   And Exhibit No. 34 is a letter dated September 7, 2011, correct?
   A.   Correct.
   Q.   And September 7, 2011 is after the policy memorandum, which is Exhibit No. 12, June 17, 2011?
   A.   Correct.
   Q.   And certainly it is after -- certainly after whatever clarification that the AGO made with respect to the applicability of the 2L regulations which was back in 2009, correct?
   A.   Yes, the clarification regarding the applicability of the natural attenuation or altered corrective action provisions in the 2L rules.
   Q.   And, in fact, Mr. Hart, even before the formal promulgation of the policy and its flowchart, and all the way through the Dan River spill, the DEQ and Duke Energy Progress were working through the flowchart with respect to Duke Energy

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Progress' coal ash ponds, isn't that right?
   A.   Let me look back at the flowchart. Sure, yes, they were. The issue was they were supposed to begin working on that at a minimum in accordance with the USWAG policy in 2007, 2008 time frame.
   Q.   So you don't dispute that they were working through in the manner that the flowchart lays out? You just say it should have happened in 2007 and '08, instead of 2010, '11, '12, is that basically what you are saying?
   A.   Well, I would say there are certainly putting wells at the compliance boundary, trying to further evaluate background conditions.
        I don't know that they -- for whatever reason, they never really got to corrective action. So they started in 2011.
        Certainly by 2014 they should have potentially depending on the site, be in the corrective action process.
        MR. MEHTA: Let's see. Martin,

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how are we doing on our videotape.
        THE VIDEOGRAPHER: We can take a break now.
        MR. MEHTA: Okay, let's take a short.
        THE VIDEOGRAPHER: We are going off the record at 2:58 p.m. This is the end of media number four.
        (Recess was taken from 2:58 p.m. to 3:12 p.m.)
        THE VIDEOGRAPHER: We are back on the record at 3:12 p.m. This is the beginning of media number five.
        BY MR. MEHTA:
   Q.   Thank you. Mr. Hart, we are going to try to show you an exhibit through this marvelous mechanism, which will be marked as Exhibit No. 9 for your deposition.
        And it is a March 10, 2011 letter from DEQ to Duke Energy Progress Sutton plant. We will give it a minute and see if it pops up. Can you see it, Mr. Hart?
   A.   Yes.
   Q.   And I don't know whether you can scroll down and look at the rest of it,

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but if you need to, just let us know and Meredith can certainly do that.
        Well, I guess she is doing that. Is this a document that you have seen before?
   A.   I don't believe so, no.
   Q.   And Meredith, if you scroll all the way down, there will be a bates number. Keep going.
        It looks like it was part of the Duke Sutton -- too far -- Duke Sutton materials that were in one of the databases that I think you said you had access to and reviewed.
        But you don't recall actually seeing this particular document, do you?
   A.   No. No. The Relativity Database is like a black hole.
   Q.   I have no comment on the Relativity Database, but there are plenty of very smart people who can find things in there.
   A.   Yeah, I understand. I understand.
   Q.   In any event, have you had an opportunity to at least skim what the

letter is saying? We can scroll up and down.

A. Yeah, if you could just scroll to the first page. Yeah, that would be great. Right there, that's good.

Q. Just tell me when you're ready.

A. Okay. Yeah, I'm ready.

Q. And if you want to go on to the second page in this short paragraph on the second page, and tell me when you're ready.

A. Yeah.

Q. Mr. Hart, the letter indicates in the first paragraph, and if we can bring it back up, Meredith, if you want so Mr. Hart can review it as we are talking.

But the letter indicates in the first paragraph that DEP had previously submitted a report of a Phase I assessment, is that right?

A. Yes.

Q. And submission of such a report is part of what you have to do under the 2L rules, is that right?

A. I'm sorry, could you say that

again.

Q. Submission of a report like this I guess it's called a Phase I groundwater assessment report, is something that the regulated entity would have to do under the 2L rules, is that right?

A. Typically. I haven't seen the report itself, but, yes, an assessment report would be typical under the requirements of the 2L rules, yes.

Q. And the second paragraph of this letter recaps well locations, including wells situated off of the Sutton plant property to investigate previous arsenic reports. Is that what it says? I'm paraphrasing.

A. Yes, that's correct.

Q. And the third paragraph indicates that arsenic is not actually crossing the compliance boundary, but that boron and total dissolved solids have crossed the compliance boundary, correct?

A. Correct.

Q. And the paragraph continues at the conclusion of the study that I guess is

the phase one assessment, is that the recommendation is a plan for continued assessment of the extent of non-compliant groundwater conditions be devised, and that a plan for permanent monitoring wells be developed for continued monitoring of plume migration and attenuation.

Is that pretty much what the end of the third paragraph says?

A. Yes.

Q. And the fourth paragraph, which is on the second page, says that the agency concurs with the recommendations and basically says go ahead and do what was recommended, right?

A. That's what it says, yes.

Q. And attenuation here would mean natural attenuation, which is one of the options available under the 2L rules for ultimate closure, correct?

A. Can you scroll back up so I can read that sentence? Thank you. It says the court recommends a plan for permanent well installation for monitoring the contaminant plume migration and attenuate,

yes.

Q. So attenuation in that context would mean natural attenuation, correct?

A. I read that to determine if the plume is migrating or attenuating or and attenuating in the context of -- I mean you have -- to have a natural attenuation corrective action plan, you have to show that it actually is going to attenuate within some reasonable timeframe so --

Q. Sorry, go ahead.

A. I think what they are saying is we are going to put in wells to see if the plume is migrating and attenuating, which would be strange.

But anyway, it's not saying this is our corrective action plan, this natural attenuation. It's saying we are going to recommend that we further evaluate the plume over time to see if it's migrating, and I would say it's probably more appropriate to say or attenuating.

Q. So in effect, this is a letter that says from the DEQ to Progress, we got

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your consultant's report, we have reviewed the report. It recommends that you do X and Y and we concur that you do X and Y and one of the potential outcomes would be -- could be I think you are probably right that and should be an or, could be natural attenuation. That's the way you read this?

A. No, not really. I mean I read this as we need to collect additional information to -- which is not -- pretty standard process to evaluate the plume, whether it's migrating or not, and evaluate whether it will attenuate or if it's undergoing any type of attenuation, which would be unusual for boron, but nevertheless, it wouldn't be unusual for us to do some evaluation of plume migration and attenuation.

Q. In this letter -- I mean you have probably seen hundreds of letters exactly like this, have you not, over the course of your career, maybe thousands?

A. Yes, I have seen letters like this, yes.

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Q. It's a very normal ordinary course of correspondence between the regulator and the regulated entity, correct?

A. Yes, I would say so.

Q. Turn, if you would, Mr. Hart, to page 13 of your testimony. The very first bullet at the top of the page, what is the time frame that is covered by this bullet?

A. I'm not sure I understand your question.

Q. Well, in many of your bullets you actually have a time frame that's embedded in the bullet. There wasn't one here, so I wondered if you had a time frame that this bullet addresses? Are we talking 2000s? Are we talking 1989? What are we talking about?

A. I mean I would say any time the 2L standards were in effect. I mean, let's see, the latest -- I guess after '89 potentially.

Q. Well, whatever the time frame is, is it normal when installing monitoring wells, the buy in of the regulator as to where the well is to locate?

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A. Not necessarily. It depends on the program. A lot of times there are programs where you install them without regulatory oversight or concurrence.

Q. Under what circumstances would you do it without regulatory oversight or concurrence?

A. Well, if you are in the REC program for North Carolina, Registered Environment Consultant program, that's R-E-C, it's basically a consultant oversight program.

So you don't get a lot of -- you don't get any feedback from DEQ. I'm not going to say any. You don't get much, if any, feedback from DEQ.

We have had -- I had even in the RCRA program in North Carolina hazardous waste section -- Si RCRA is R-C-R-A, where they have requested wells and we have asked them if they wanted a work plan and they said, no, go ahead and do it.

So you don't have to get approval from the agency. It certainly doesn't hurt.

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Q. Have you ever done any groundwater monitoring for a regulated utility?

A. Not that I can -- no, I don't believe so.

Q. Can you conceive of a situation in which a regulated utility would not get the buy in of its regulator in siting a monitoring well?

A. I mean there could be some instances. For example, if there is contaminated offsite water supply well and you want to know if it's coming from your facility, I can see that under an initial response action, you wouldn't want to wait for regulatory approval -- human health.

Q. There are no matters of human health associated with the Duke Energy Progress coal ash ponds, are there?

A. I don't know. At Sutton there was certainly concerns about contamination of an offsite public supply well.

Q. Were those concerns back in the 1980s or were they concerns in the 2000s?

A. I think they went all the way to 2000s, as I recall, because they agreed to

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at some point to connect those folks to city water.
Q. That was a requirement of a spec sheet, was it not?
A. I believe it's a C4 CAMA. I mean could be wrong, but --
Q. So do you think that at the Sutton facility there was some concern about contamination of a water supply well in the 2000s?
A. That's my recollection.
Q. Apart from that situation, there were no impacts from Duke Energy Progress coal ash basins to any water supply well, isn't that correct?
A. I believe there were at least one well near the Asheville facility that they believe was contaminated by the Asheville facility, and they connected to property owners to city water.
Q. Are there other situations in which a water supply was contaminated by a Duke Energy Progress coal ash basin?
A. That's all that I can remember.
Q. Skip ahead, Mr. Hart, and you will

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be encouraged to know we are skipping ahead a bunch of pages, to page 46 of your testimony.
A. Okay.
Q. Right at the bottom of the page carrying on to page 47, you provide some examples of your experience with coal ash and metals contamination, is that right?
A. Yes.
Q. And the first one is I have and am assisting several clients with assessment of groundwater impacts from permitted coal ash landfills and from locations where coal ash was placed as a beneficial fill. Do you see that?
A. Yes.
THE COURT REPORTER: You are breaking up a little bit, Kiran.
BY MR. MEHTA:
Q. Sorry. I will bring the phone a little closer.
Are the situations with the permitted coal ash landfills and beneficial fill ones that you testified about in the DEC deposition?

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A. Yes.
Q. As I'm recalling, there was one with the Town of Chapel Hill. What were the other ones, just briefly?
A. So there is the Town of Chapel Hill. The other one was at the former Pillowtex facility where they sluiced ash to their wastewater treatment plant area and then put it in a landfill, and then the other was the Camp Hope.
Q. Was that the Holy Angels one?
A. Yes, Holy Angels.
Q. And that was one where you tested the water supply well and found that there was no issues with that well, correct?
A. That's correct, yes. There was no issues with -- go ahead, I'm sorry.
Q. That was in the vicinity of the Allen plant, correct?
A. That's correct, yes. There were issues with the storm water, from a storm water line that ran through the fill, contamination getting into Lake Wylie.
Q. Is it correct that none of these instances had anything to do with a

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Progress Energy coal ash pond, correct?
A. That's correct.
Q. And in your second bullet, you indicate you are assisting a client with the evaluation of environmental liability risks. Is that the situation up in Michigan that you testified about in the DEC deposition?
A. Yes. Michigan is one of them. There is other facilities that we looked at as well, but Michigan is the Consumer Energy facilities in Michigan are the main ones.
Q. And then the third bullet you indicate you are assisting clients with assessment and remediation of environmental contamination from metals at industrial facilities.
In this bullet you are not talking about coal ash-related experience, are you?
A. No, no. This is experience related to metals, which would be the primary compounds of concern from coal ash.

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Q. And compounds of concern as a result of the process of burning and then -- burning the coal and disposing of the ash in a basin, correct?
A. Yes.
Q. Is the facility that is the subject of the third bullet the Occidental Chemical facility that you testified about in the DEC deposition?
A. The first one, yes. Yeah, the large chromium products manufacturer.
Q. Oh, I see. So these are different facilities.
A. Three different facilities.
Q. The large chromium products manufacturer is the Occidental Chemical facility?
A. Yes, former Occidental Chemical facility.
Q. What is the metal salts manufacturing and recycling facility?
A. That is the Umicore, U-m-i-c-o-r-e, Cobalt Specialty Metals facility in Arab, Alabama.
Q. Is that spelled A-r-a-b, Alabama?

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A. A-r-a-b, yes.
Q. And the third one would be a sodium hydro sulfate manufacturing facility. What is that?
A. That is the former Clariant facility, C-l-a-r-i-a-n-t, in Kalama Washington, K-a-l-a-m-a.
Q. So the only one in North Carolina would have been the Occidental Chemical facility, correct?
A. Of these, right.
Q. Why do you think the Occidental Chemical site is comparable to any of the Duke Energy Progress ash basins?
A. From what aspect are you talking about?
Q. You bring it up, that I presume you are highlighting to show that you have experience with respect to the ash basins. I just wondered why you think it's comparable experience?
A. Well, it's related to metals. The metals behave in unique fashions in the environment, so it's really demonstrating experience with metals contamination.

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Now, there are certainly parallels, which I discussed later in my testimony regarding this facility and differences in how this facility handled their basin with groundwater contamination from a permit, NPDES permit, and disposal of residual solids permit, how they addressed their groundwater contamination and how DEP did, which is discussed later in my testimony.
Q. Is that discussion later in your testimony beginning on page 92 of your testimony?
A. Yes.
Q. When did you first become involved with the Occidental Chemical site, Mr. Hart?
A. In 2013, I believe.
Q. Did you takeover from some other environmental consultant?
A. Yes.
Q. Who was that?
A. It was CRA.
Q. CRA?
A. Yeah, which I believe now is GHD.

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Don't ask me what that stands for.
Q. Consolidate the environment consultants.
You provide a lot of information concerning the Occidental Chemical facility that well predates 2013. What was the source of your information?
A. Well, information, historical reports, as well as discussions with people that were involved in the facility.
Q. You indicate, I think -- I'm looking for the reference. It's on page 93, line five, that groundwater impacts were identified in approximately 1975. Do you see that?
A. Yes.
Q. And then you go through a series of events what occurred after 1975. Could you, again, briefly walk us through the various steps that Occidental Chemical took with respect to the groundwater contamination that was identified in 1975?
A. I believe the first identification of contamination was in 1975 around what they call a plant process area, which is

where the main plant is, and I believe there was some contamination in the water supply well.

I think they also had some suspected releases, so they began to evaluate the magnitude and extent of contamination. I'm not sure when they first installed wells around the lagoon areas.

Q. It indicates that by 1988 the plant had installed approximately 180 wells, including 50 or 60 wells used for groundwater remediation, is that right?

A. Yes.

Q. So when between 1975 and '88 did Occidental Chemical install these wells?

A. I think they were doing installation of wells throughout that time period, and then they also started operating a groundwater extraction and treatment system.

I can't remember the exact date when it started, but it may have been as early as 1978 to help control the extent of contamination while the assessment was

still ongoing.

Q. Was the groundwater impact --

A. Go ahead, I'm sorry. Throughout this time frame '75 to '88, they were doing groundwater assessment, but also groundwater remediation concurrently.

Q. Do you know when they first started -- when they first drilled, if that's the right word, the assessment wells?

A. Based upon my recollection, it started in -- soon after they identified the contamination, because there are wells up there that date from the late 1970s, monitor wells. They are pretty old.

Q. Were there groundwater impacts as a result of this contamination to drinking water supplies?

A. No. Well, I'm not sure if they used -- they may have used one of the wells for drinking water, but then they connected to city water after that.

So they had several production wells out there, and one of them may have been used for drinking water.

Q. When you say "production wells," what do you mean?

A. They use a lot of water in the process. So they would pump groundwater for some of their process water. They would also pull in water from the northeast Cape Fear River as well.

Q. So when you are talking about production wells, it's wells used to generate the water needed in the plant production process, is that right?

A. That's correct. That's correct.

Q. What did this plant do?

A. They take chromite ore from South America and extract chromium products from it by converting trivalent chromium to hexavalent chromium. They wait -- go ahead.

Q. Was the contaminant of concern chromium?

A. There is several. There is chromium is obviously the main one. Vanadium which is also, although not produced, it's part of the chromite ore. It's contained in it.

They also have issues with total dissolved solids, chloride, iron, and then there is also some other metals of -- some of the water has low pH, because of the hexavalent chromium. Chromic acid has been spilled.

So some of the metals that are found in groundwater are leaching out of the soil at a low pH, rather than necessarily from a process if that makes sense.

Q. So are these -- that prompts a question. Are these contaminants the result of the basic manufacturing process that the plant --

A. Yes, and the wastewater treatment plant, or -- and the wastewater treatment plant where they have lagoons as I mentioned.

Q. Is the lagoon a place -- what happens in the lagoon?

A. So the residual solids from -- when the chromite ore is processed, they first take out the hexavalent chromium, which is a highly -- it's a soluble form

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of chromium, and then in the wastewater treatment plant they reconvert the hexavalent chromium to trivalent chromium using several processes, which include ferric oxide.

So those residual solids, after they are converted back to trivalent chromium are placed back or are placed into the lagoon.

Q. So in effect you processed the immediate waste product in the wastewater treatment facility and render it less bad.

Is that essentially what happens and then it goes into a lagoon?

A. Right. So the -- yeah, so the intention is -- hexavalent chromium is soluble, but trivalent chromium is insoluble.

So in that conversion process you are putting trivalent chromium -- sludge with trivalent chromium into the lagoon.

It also has some in that treatment process, what they have used different things over time that now I believe they use pickle liquor, which is an iron

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chloride to do that conversion process to render it -- the chromium insoluble before it goes into the lagoon.

Q. And then when it's in the lagoon, what happens to it?

A. Well, it's in the lagoon now. So it will eventually have to be closed. Now, the old lagoon, one lagoon was closed in 1993 using a geo-textile layer with an impermeable polyethylene liner with DEQ concurrence and approval.

The other lagoon is still being used.

Q. In what form is the lagoon still be used? Is it a lined lagoon? Is it an unlined lagoon?

A. It is an unlined lagoon. It's former limestone quarries.

Q. Is there any requirement or contemplation that that lagoon will be closed?

A. Well, it has to be closed at some point when it's no longer able to be used, when it's full much.

Q. Well, how long has it been in use?

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A. 19 -- so there are actually two lagoons, two former quarries, and so they started using one of them in 1977.

Q. So there is a lagoon in use today that started being used in 1977, is that right?

A. That's correct.

Q. And is there another lagoon also in use today?

A. Yes.

Q. And when did it become -- when did it first start to be used?

A. I'm not sure exactly when it was started to be used.

Q. Was it before 1977 or after '77?

A. I believe after. It's a little complex because Occidental doesn't own the facility anymore, although they have some -- well, they have liability for the environmental contamination.

So Elementis, who operates the plant now has -- they have -- for one of the lagoons they have joint responsibility to close it. The other one Occidental does well. At least now Elementis can

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potentially use that lagoon, too. So like I said, it's a little complex.

Q. Is some combination Occidental and -- is it Elementis?

A. Yes, E-l-e-m-e-n-t-i-s.

Q. Elementis. Some combination of Occidental and Elementis paying for all of this remediation work?

A. Only Occidental from a groundwater contamination issue, not for eventual closure.

Q. Who pays for the eventual closure?

A. Well, it depends on their relative contributions of residual solids for each lagoon.

Q. So it will be some kind of allocation based on volumes of waste going to the lagoon, lagoons?

A. Yes. That's correct, yes.

Q. Mr. Hart, let's go back to your quantification exercise for the Duke Energy Progress rate case. We talked early in the deposition about the time value of money aspect of that quantification, but you had two other

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aspects of the quantification, which you called step A and step B, correct?

A. Correct.

Q. Step A is the removal of what water connection costs, correct?

THE COURT REPORTER: I'm sorry?

THE WITNESS: That's correct, yes.

THE VIDEOGRAPHER: Removal of what? Step A is the removal of what?

BY MR. MEHTA:

Q. Water connection costs. Sorry, getting late in the day and I am starting to lean back. I need to lean forward. Let's try that one again.

Mr. Hart, step A in your quantification exercise is the removal of water connection costs, correct?

A. That's correct.

Q. And you acknowledge that this is a statutory requirement of CAMA, correct?

A. Yes, the amendment, 2016 amendment, yes.

Q. The statute as amended requires these expenditures by Duke Energy Progress, correct?

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A. Correct.

Q. And you say that the requirement came about because of a loss of public confidence in Duke Energy Progress, is that right?

A. Well, I think that was one of the reasons. I think there are others. There was just a lot of uncertainty about where the extent of the groundwater contamination was, whether there was -- when they went out to sample people's water supply well, whether there was attribution to the facility or not, whether back down conditions had been adequately determined.

So there was a lot of confusion with regard to whether the detections they were seeing in water supply wells were from Duke facilities or not.

In my opinion, it was unheard of or if there aren't any contaminated water supply wells, which we discussed before, for an entity to have to connect everyone within a half mile to some alternate water source if they are not the source of the

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contamination.

In my opinion, that came about because of the lack of definition of the groundwater impact and inability of determining background concentrations for the different metals.

Q. We did go over this in your DEC testimony, but, Mr. Hart, for the DEP wells, you also have performed no surveys of legislators, regulators as to why this requirement came into being, correct?

A. No, not any specific surveys. I did look back in published articles from newspapers in this time frame about why this was included in the CAMA amendments, and it was clear there was a lot of uncertainty about whether there was groundwater contamination from the facilities or not. I'm certain it was several facilities, but --

Q. Which facilities?

A. Well, I think there was concern at the Allen facility --

Q. I'm talking about Duke Energy Progress facilities, sorry?

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A. Well, at that time they were combined. In the time of the CAMA amendments, so it wasn't specific to any DEP facility potentially. I don't recall.

I just know that Allen was one of the people that had significant issues with because there were water supply wells directly next to the plant that had evidence of potential contamination from the facility.

Q. So what impact did DEQ's somewhat less than stellar rollout of the information concerning the wells in the general vicinity of the Allen plant have with respect to this issue?

A. Well, there is certainly some I guess confusion about some health risk evaluations that have been done by DEQ that were later, and I can't remember if they said there was contamination and they switched or whether they said there was not contamination, and they switched -- not contamination, but there were concerns with the well and they said there weren't concerns with the well. I can't remember

which way it went.
Q. Either way, they said something and switched, correct?
A. That's my recollection, yes.
Q. Well, my question to you is, to what extent did that confusion on the part of DEQ in the rollout of this information have on the requirements that was then embedded in the CAMA amendments that all dwellings, I think it was, within a half mile of the plant be connected to public water?
MS. TOWNSEND: Objection to form.
THE WITNESS: Well, I'm not certain how to answer that question, other than to say I think if DEP had -- with regards to the Allen plant, DEC had gone out and established the area of contamination and sampled water supply wells, had documented what the background contamination levels were, not contamination level, but what background levels were, which weren't done until 2016 or 2017 time frame.
If that had been done earlier,

then the public would have and DEQ would have had greater confidence in saying, yes, we agree that these wells are or are not contaminated.
But because that hadn't been done, there was just a lot of uncertainty about whether the contamination was or wasn't associated with this facility or the metals that were detected.
BY MR. MEHTA:
Q. What was the ultimate determination of that question?
A. I don't know. As I understand it, there were some people that quit. There were depositions, and I don't exactly now all the details of it. So I'm not exactly sure, other than obviously I would say in the amendments of CAMA there was a requirement to connect people to alternate water supplies.
Q. And those amendments from CAMA went into effect in 2016, correct?
A. That's correct.
Q. But you don't know what the ultimate determination about whether

anybody's water supply was actually impacted by the Allen plant, how that ultimate determination was made?
A. I don't recall. My recollection is there were some wells near the Allen plant that were contaminated from the Allen plant, but I could be wrong. But that's my recollection.
Q. But certainly the wells that you tested, the Holy Angels well was not contaminated from the Allen plant, was it?
A. No, we weren't testing to see if it was contaminated from the Allen plant. It was on the other side of the topographic divide, and fairly far away from the coal ash ponds.
We were testing it to see if the groundwater was contaminated from the coal ash fill that had been placed there.
Q. In either event, or in any event, when you tested that well, it was not contaminated by whatever source was suspected of potentially contaminating it, is that correct?
A. That is correct, yes, we were very

concerned that these handicap people that used the camp wanted to make sure that they weren't exposed to contaminated drinking water.
Q. Did the Holy Angels camp get connected to city water as part of this program?
A. I don't know. I believe they did it. I'm not positive. Their well was also sampled by DEC's consultants. I do believe they were within a half mile.
Q. Within the half mile radius?
A. I believe so, yes.
Q. Mr. Hart, step B of your quantification deals with excavation costs for what you term are old ponds, right?
A. Yes, correct.
Q. And refer, if you wish, to Exhibit No. 6, which are in your work papers. The first page, if you printed it out, recaps both step A and step B, correct?
A. That is correct.
Q. And for the Asheville plant, you identify 100 percent of the excavation as being "old basins," right?

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A. Correct.
Q. One of those basins is not old, meaning not in use, was it?
A. The 64 pond was out of use in '81. It certainly didn't receive any -- may have received some, but it primarily was used for storm water, and I don't exactly know where the storm water came from.
It did not even have an outfall after 1981 until more recently when they started excavating a 1982 basin.
Q. But the 1982 basin is not what you would classify as a "old basin," was it?
A. No, that's correct, the 1982 basin had already been excavated.
Q. So is the 99,000,000 -- let's see, I guess it's $99,274,176 cost for excavation entirely with respect to the 1964 basin?
A. From my understanding from reading Ms. Bednarcik's testimony, is that the -- I'm going to use a different number because you included the water supply well cost. The $99,121,747 is for excavation of the 1964 basin. I believe the 1982

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basin was -- had been excavated by 2016.
So they wouldn't be included in the costs in the current rate case.
Q. What makes you think that the 1982 basin was excavated by 2016?
A. Well, that's what their documents say, it was completed in 2016, and full decommissioning was completed in January of 2018. That's what the documents say that I read.
Q. For all of the other plants, you make some kind of an allocation between the, "old basins" and the not old basins, correct?
A. That's correct. Well, for the ones -- the other ones for Cape Fear, HF Lee, Roxboro and Sutton.
Q. So did Mayo, Robinson and Weatherspoon not have "old basins"?
A. Yes, that's correct. Well, they may have had old basins, but they are still in use or they are part of an not in use -- were used until recently or still in use.
They were part of a larger basin.

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In other words, there wasn't a basin that was taken out of service at some time.
Q. And when the basins were taken out of service at some earlier time, they were dealt with in whatever way the law required at that earlier time, weren't they?
A. I don't know how you -- what you mean by dealt with?
Q. Well, I mean some of these basins were by the time they were excavated, fully decanted, some kind of soil cover was placed on them and forest were growing on them at least at Cape Fear and HF Lee, were they not?
A. No, I don't think there was -- in fact, I think if you read -- I don't know if it's Cape Fear or HF Lee that says you could still see they were forested, but you could still see coal ash on the ground. There was no attempt to close them or cover them, to my knowledge.
Q. But at the time that they were closed, not in a regulatory sense, but in the sense that you are using it, that is,

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they were not used anymore, it was not impermissible to do it in the way it was done, isn't that correct?
A. It was, as I understand, not impermissible, but it certainly would have been prudent and reasonable, especially in the light of the groundwater contamination to prevent infiltration of water through these basins that continued to contribute to groundwater contamination.
THE VIDEOGRAPHER: Mr. Mehta, we may need to take another break here in a couple of minutes.
MR. MEHTA: Okay. Why don't we take ten minutes. That will take us to 4:30, and I am either finished or will be very shortly.
THE VIDEOGRAPHER: We are going off the record at 4:17 p.m. This is the end of media number five.
(Recess was taken from 4:17 p.m. to 4:29 p.m.)
THE VIDEOGRAPHER: We are back on the record at 4:29 p.m. This is the beginning of media number six.

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MR. MEHTA: Mr. Hart, I don't have any further questions for you this afternoon, and I appreciate your time.

THE WITNESS: All right, thank you.

MS. TOWNSEND: No questions from me. Thank you.

THE VIDEOGRAPHER: So that's it?

MR. MEHTA: Yes, thank you.

MS. TOWNSEND: That's it.

THE VIDEOGRAPHER: We are going off the record at 4:29 p.m.

(Signature reserved.)

(Whereupon, at 4:29 p.m., the taking of the instant deposition ceased.)

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E R R A T A S H E E T

IN THE MATTER OF APPLICATION OF DUKE ENERGY CAROLINAS, LLC FOR ADJUSTMENT OF RATES AND CHARGES APPLICABLE TO ELECTRIC SERVICES IN NORTH CAROLINA

DEPOSITION OF: STEVEN C. HART

Please read this original deposition with care, and if you find any corrections or changes you wish made, list them by page number, line number and state reason for change below. DO NOT WRITE IN THE DEPOSITION ITSELF. Return the deposition to this office after it is signed. We would appreciate your prompt attention to this matter.

To assist you in making any such corrections, please use the form below. If supplemental or additional pages are necessary, please furnish same and attach them to this errata sheet.

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Signature of Witness

SUBSCRIBED and SWORN TO before me this ___day of _______________________, 20____.

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NOTARY PUBLIC

My Commission expires: ___________________

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CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA}
COUNTY OF MECKLENBURG }

I, Andrea L. Nobrega, the officer before whom the foregoing deposition was taken, do hereby certify that the witness whose testimony appears in the foregoing deposition was duly sworn by Whitney Ellswirth; that the testimony of said witness was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this deposition was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

Andrea L. Nobrega
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ANDREA L. NOBREGA
Court Reporter and Notary
Public in and for North Carolina

My Commission expires: 11-25-21

Exhibits

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Step A and B Cost

From Bednarcik Testimony - Costs 9/1/17 - 6/30/19

	Asheville	Cape Fear	HF Lee	Mayo	Robinson	Roxboro	Sutton	Weatherspoon	
EHS	$ 5,172,857.00	$ 1,376,679.00	$ 1,916,128.00	$ 4,642,036.00	$ 671,709.00	$ 4,886,319.00	$ 3,666,022.00	$ 1,669,824.00	
Basin Closure/Engineering Design	$ 91,005,148.00	$ 4,572,585.00	$ 7,109,808.00	$ 4,678,767.00	$ 19,611,717.00	$ 7,511,385.00	$ 97,575,750.00	$ 22,293,532.00	
Beneficiation Plant Construction		$ 33,341,762.00	$ 73,427,305.00						
Permanent Water Supply	$ 152,420.00	$ 7,464.00	$ 508,958.00	$ 362,476.00	$ 144,030.00	$ 1,814,598.00	$ 243,574.00	$ 247,576.00	$ 3,481,096.00
Basin Support Projects	$ 3,646.00	$ -	$ 165,331.00	$ 8,023,288.00	$ 5,557.00	$ (3,837.00)	$ -		
Permitting	$ 309,843.00	$ 326,403.00	$ 347,211.00	$ 574,031.00	$ 62,363.00	$ 382,257.00	$ 182,652.00	$ 367,571.00	
Other	$ 2,630,253.00	$ 2,065,761.00	$ 3,134,925.00	$ 4,239,901.00	$ 266,922.00	$ 2,254,543.00	$ 892,126.00	$ 1,096,334.00	
Total All Costs	**$ 99,274,167.00**	**$ 41,690,654.00**	**$ 86,609,666.00**	**$ 22,520,499.00**	**$ 20,762,298.00**	**$ 16,845,265.00**	**$ 102,560,124.00**	**$ 25,674,837.00**	**$ 415,937,510.00**
Total without Permanent Water Supply	**$ 99,121,747.00**	**$ 41,683,190.00**	**$ 86,100,708.00**	**$ 22,158,023.00**	**$ 20,618,268.00**	**$ 15,030,667.00**	**$ 102,316,550.00**	**$ 25,427,261.00**	**$ 412,456,414.00**

									Total
Step A (Remove Water Connection Costs)									
Amount Excluded - Permanent Water Supply	**$ 152,420.00**	**$ 7,464.00**	**$ 508,958.00**	**$ 362,476.00**	**$ 144,030.00**	**$ 1,814,598.00**	**$ 243,574.00**	**$ 247,576.00**	**$ 3,481,096.00**

Step B (Remove Old Ash Basin Costs)									
Ash in "Old" Basins (cy)		2,458,333	1,425,000			5,894,901	4,633,028		
Total Ash in All Basins (cy)		4,808,333	5,191,667			16,706,984	10,040,894		
% in Old Basins	100%	51%	27%			35%	46%		
Amount Excluded Step B	**$ 99,121,747.00**	**$ 21,311,161.59**	**$ 23,632,777.08**	**$ -**	**$ -**	**$ 5,303,428.43**	**$ 47,210,481.56**	**$ -**	**$ 196,579,595.66**

									Total
Total Amount Excluded Steps A and B	**$ 99,274,167.00**	**$ 21,318,625.59**	**$ 24,141,735.08**	**$ 362,476.00**	**$ 144,030.00**	**$ 7,118,026.43**	**$ 47,454,055.56**	**$ 247,576.00**	**$ 200,060,691.66**
Notes	All Closure Costs Excluded because 1964 ash pond esentially taken out of service in 1982 and 1982 basin already excavated	51% of Closure Costs Plus Water Supply Connection Costs Excluded	27% of Closure Costs Plus Water Supply Connection Costs Excluded	Only Water Supply Connection Costs Excluded	Only Water Supply Connection Costs Excluded	35% of Closure Costs Plus Water Supply Connection Costs Excluded	46% of Closure Costs Plus Water Supply Connection Costs Excluded	Only Water Supply Connection Costs Excluded	

Summary

Total All Costs from Bednarcik	**$ 415,937,510.00**
Total Amount Excluded (Steps A and B)	**$ 200,060,691.66**
Amount Not Excluded (Carried to Step C)	**$ 215,876,818.34**

Start Year	**Years from 2014**				
1992	23				
		Non-Excluded Costs from Steps A and B		$ 215,876,818.34	
	Average Interest Rate 1992-2014			**Calculated Value Approx Equal to to Non Excluded Cost Above**	
	0.024	Cost 23 Years Earlier that Equals Approx. $215MM	**$ 125,000,000.00**	$215,679,573.34	Future Value of Approx. $215MM over 23 years at average interest rate of 2.4% is approxiamtely this Cost
				$90,679,573.34	**Amount to Exclude Due to Time Value of Money if Closure Planning Started in 1992 Instead of 2014**

Start Year	**Years from 2014**				
1996	19				
		Non-Excluded Costs from Steps A and B		$ 215,876,818.34	
	Average Interest Rate 1996-2014			**Calculated Value Approx Equal to to Non Excluded Cost Above**	
	0.023	Cost 19 Years Earlier that Equals Approx. $215MM	**$ 140,000,000.00**	$215,657,753.17	Future Value of Approx. $215MM over 19 years at average interest rate of 2.3% is approxiamtely this Cost
				$75,657,753.17	**Amount to Exclude Due to Time Value of Money if Closure Planning Started in 1996 Instead of 2104**

Start Year	**Years from 2014**				
2009	6				
		Non-Excluded Costs from Steps A and B		$ 215,876,818.34	
	Average Interest Rate 1996-2014			**Calculated Value Approx Equal to to Non Excluded Cost Above**	
	0.0144	Cost 6 Years Earlier that Equals Approx. $215MM	**$ 198,000,000.00**	$215,735,012.14	Future Value of Approx. $215MM over 6 years at average interest rate of 1.44% is approxiamtely the Revised Cost
				$17,735,012.14	**Amount to Exclude Due to Time Value of Money if Closure Planning Started in 2009 Instead of 2014**

Excel Future Value Calculation

FV(rate, nper, [pmt], [pv], [type])	Value Used
where,	
rate is the interest rate per period (as a decimal or a percentage);	Avg Interest Rate During Period
nper is the number of periods over which the investment is made;	Years from Start Point to 2014
[pmt] is the regular payment per period (if omitted, this is set to the default value 0);	No Payments (0)
[pv] is the present value of the investment (if omitted, this is set to the default value 0);	Present Value = $215MM
[type] specifies whether the payment is made at the start or the end of the period.	Paymengt at End of Period (0)

This can have the value 0 or 1, meaning:
0 - the payment is made at the end of the period (as for an ordinary annuity);
1 - the payment is made at the start of the period (as for an annuity due).
If omitted, the [type] argument is set to the default value 0.

Note that, in line with the general cash flow sign convention, the FV function treats negative values as outflows and treats positive values as inflows.

Interest Rates for Step C
I/A

1989	4.67%	4.83%	4.98%	5.12%	5.36%	5.17%	4.98%	4.71%	4.34%	4.49%	4.66%	4.65%	4.83%			
1990	5.20%	5.26%	5.23%	4.71%	4.36%	4.67%	4.82%	5.62%	6.16%	6.29%	6.27%	6.11%	5.39%			
1991	5.65%	5.31%	4.90%	4.89%	4.95%	4.70%	4.45%	3.80%	3.39%	2.92%	2.99%	3.06%	4.25%	2.40%	1992	2014
1992	2.60%	2.82%	3.19%	3.18%	3.02%	3.09%	3.16%	3.15%	2.99%	3.20%	3.05%	2.90%	3.03%			
1993	3.26%	3.25%	3.09%	3.23%	3.22%	3.00%	2.78%	2.77%	2.69%	2.75%	2.68%	2.75%	2.95%			
1994	2.52%	2.52%	2.51%	2.36%	2.29%	2.49%	2.77%	2.90%	2.96%	2.61%	2.67%	2.67%	2.61%	2.30%	1996	2014
1995	2.80%	2.86%	2.85%	3.05%	3.19%	3.04%	2.76%	2.62%	2.54%	2.81%	2.61%	2.54%	2.81%			
1996	2.73%	2.65%	2.84%	2.90%	2.89%	2.75%	2.95%	2.88%	3.00%	2.99%	3.26%	3.32%	2.93%			
1997	3.04%	3.03%	2.76%	2.50%	2.23%	2.30%	2.23%	2.23%	2.15%	2.08%	1.83%	1.70%	2.34%			
1998	1.57%	1.44%	1.37%	1.44%	1.69%	1.68%	1.68%	1.62%	1.49%	1.49%	1.55%	1.61%	1.55%			
1999	1.67%	1.61%	1.73%	2.28%	2.09%	1.96%	2.14%	2.26%	2.63%	2.56%	2.62%	2.68%	2.19%			
2000	2.74%	3.22%	3.76%	3.07%	3.19%	3.73%	3.66%	3.41%	3.45%	3.45%	3.45%	3.39%	3.38%			
2001	3.73%	3.53%	2.92%	3.27%	3.62%	3.25%	2.72%	2.72%	2.65%	2.13%	1.90%	1.55%	2.83%			
2002	1.14%	1.14%	1.48%	1.64%	1.18%	1.07%	1.46%	1.80%	1.51%	2.03%	2.20%	2.38%	1.59%	1.44%	2009	2014
2003 2.60%		2.98%	3.02%	2.22%	2.06%	2.11%	2.11%	2.16%	2.32%	2.04%	1.77%	1.88%	2.27%			
2004	1.93%	1.69%	1.74%	2.29%	3.05%	3.27%	2.99%	2.65%	2.54%	3.19%	3.52%	3.26%	2.68%			
2005	2.97%	3.01%	3.15%	3.51%	2.80%	2.53%	3.17%	3.64%	4.69%	4.35%	3.46%	3.42%	3.39%			
2006	3.99%	3.60%	3.36%	3.55%	4.17%	4.32%	4.15%	3.82%	2.06%	1.31%	1.97%	2.54%	3.24%			
2007	2.08%	2.42%	2.78%	2.57%	2.69%	2.69%	2.36%	1.97%	2.76%	3.54%	4.31%	4.08%	2.85%			
2008	4.28%	4.03%	3.98%	3.94%	4.18%	5.02%	5.60%	5.37%	4.94%	3.66%	1.07%	0.09%	3.85%			
2009	0.03%	0.24%	-0.38%	-0.74%	-1.28%	-1.43%	-2.10%	-1.48%	-1.29%	-0.18%	1.84%	2.72%	-0.34%			
2010	2.63%	2.14%	2.31%	2.24%	2.02%	1.05%	1.24%	1.15%	1.14%	1.17%	1.14%	1.50%	1.64%			
2011	1.63%	2.11%	2.68%	3.16%	3.57%	3.56%	3.63%	3.77%	3.87%	3.53%	3.39%	2.96%	2.16%			
2012	2.93%	2.87%	2.65%	2.30%	1.70%	1.66%	1.41%	1.69%	1.99%	2.16%	1.76%	1.74%	2.07%			
2013	1.59%	1.98%	1.47%	1.06%	1.36%	1.75%	1.96%	1.52%	1.18%	0.96%	1.24%	1.50%	1.47%			
2014	1.58%	1.13%	1.51%	1.95%	2.13%	2.07%	1.99%	1.70%	1.66%	1.66%	1.32%	0.76%	1.62%			

Total Costs Excluded

Starting Point	**1992**		
Step A and B Excluded Costs		$	200,060,692
Step C Excluded Costs		$	90,679,573
Total Excluded		**$**	**290,740,265**

Starting Point	**1996**		
Step A and B Excluded Costs		$	200,060,692
Step C Excluded Costs		$	75,657,753
Total Excluded		**$**	**275,718,445**

Starting Point	**2009**		
Step A and B Excluded Costs		$	200,060,692
Step C Excluded Costs		$	17,735,012
Total Excluded		**$**	**217,795,704**

JOHN G. HOWAT

PROFESSIONAL EXPERIENCE

Senior Energy Policy Analyst: National Consumer Law Center. 1999 - Present Boston, MA

- Advocate for enhanced low-income home energy security with particular focus on energy and utility economics, technologies and regulation
- Manage broad range of state and national low-income energy advocacy projects
- Provide expert testimony on low-income energy and utility issues before state regulatory agencies
- Support the enhancement of advocacy capacity of a national network of low-income program delivery and policy organizations through targeted advice and assistance, trainings, and maintenance of communications networks
- Track technology, economic, programmatic, regulatory and policy developments pertaining to low-income access to energy and utility service
- Provide state and federal legislative services on behalf of low-income advocates and clients
- Develop reports and publications; coordinate and present low-income energy advocacy perspectives at national energy conferences

Sole Proprietor: John Howat Associates. 1995 - 1999 Boston, MA

- Conducted market and economic analysis, analysis of customer energy consumption and load profiles, development of power supply requests for proposals, and analysis of utility rates, assets and power purchase contracts.
- Provided Legislative and Regulatory representation
- Provided communications planning and program implementation
- Registered Massachusetts Energy Broker

Resource Planning Economist: Massachusetts Department of Public Utilities. 1991 - 1995 Boston, MA

- Participated in adjudication and settlement proceedings pertaining to electric utility resource planning.
- Conducted technical analysis in conjunction with development of regulatory review policies.
- Prepared and conducted discovery and cross examinations of witnesses.
- Drafted Orders, Decisions, and internal communications.
- Acted as liaison to various public and private sector organizations.

Massachusetts State Legislature. 1985 - 1991 Boston, MA

<u>Research Director: Joint Committee on Energy. 1991</u>

- Directed all committee legislative activities.
- Hired, trained and supervised research and support staffs.
- Conducted legal research and quantitative analysis leading to development of new legislation.
- Worked with Committee Chairmen, rank and file legislators, lobbyists, members of the public and the press.

<u>Legislative Director: State Senator Sal Albano. 1988 - 1990</u>

- Coordinated all legislative and budgetary activities for Senate Chairman of the Joint Committees on Education and Public Safety, including drafting of legislation, amendments and budgetary proposals, and supervision of legislative aides and interns.
- Advised the Senator on policies and programs related to education, health care, human services, housing, the environment, public safety, and taxation.
- Coordinated public relations, including drafting of press releases and answering press inquiries.
- Developed a legislative tracking system.
- Wrote briefing materials for debates and public presentations.

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Senior Legislative Research Analyst: Joint Committee on Energy. 1985 - 1988

- Conducted research and analysis of legislation before the committee.
- Drafted new legislation relative to energy efficiency programs and policies, non-utility generation, low-income energy programs, utility rates, municipal utilities, and the "Bottle Law."

Executive Director: Association of Massachusetts Local Energy Officials. 1982 - 1985 Boston, MA

- Promoted, monitored and evaluated four statewide institutional energy conservation programs as a consultant to the Mass. Municipal Assn. and the Mass. Executive Office of Energy Resources.
- Wrote and negotiated grant proposals.
- Conducted member recruitment, fund raising and financial management.
- Produced, edited and contributed to quarterly newsletters distributed statewide.
- Organized workshops and conferences for public sector energy managers.

Teaching Assistant: Tufts University Graduate Department of Urban and Environmental Policy.
1983 - 1984 Medford, MA

- Conducted graduate workshops in financial analysis and management of local governments and non-profit organizations.
- Subject matter included cash flow, net present value, internal rate of return, business planning and benefit/cost analyses with emphasis on externalities and non-quantitative values.

Legislative Aide: Washington State Senator King Lysen. 1981 - 1982 Olympia, WA

- Conducted inquiry into energy consumption, rate structures and taxation of Direct Service Industrial customers of energy suppliers and brokers in the Pacific Northwest.
- Coordinated media relations and production of constituent newsletters.

County Coordinator/Research Analyst: "Don't Bankrupt Washington" Campaign. 1981 Olympia, WA

- Conducted analysis of economic impacts to electric utility ratepayers caused by cost overruns on five Washington Public Power Supply System nuclear power plants.
- Served as Thurston County Coordinator of the organization that sponsored Initiative Measure No. 394, requiring voter approval for bonding of public energy facilities.
- Conducted fund raising activities, coordinated the efforts of 30 volunteers, and waged an effective voter turnout campaign.

EDUCATION

Master of Urban and Environmental Policy. Tufts University. Graduate Department of Urban and Environmental Policy. Medford, Massachusetts. January, 1984.

Areas of Study: Community Energy Planning, Energy Economics, Housing Policy, Community Economic Development, Communications Methods, Financial Analysis and Management, Research Methods, Statistical Analysis, and various computer applications.

Bachelor of Arts. The Evergreen State College. Olympia, Washington. June, 1981.

Areas of Study: Economics, Political Science, American and European History.

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John Howat Regulatory Commission Testimony and Comment Experience

Case Name/Docket	Client	Topic	Jurisdiction	Date
Docket No. 32953 - Alabama Power Company	Energy Alabama and Gasp	Direct Testimony - Affordability of residential electricity service	Alabama	Dec-19
Cause No. 45253 - Duke Energy Indiana	Indiana Citizens Action Coalition, Indiana Community Action Association, Environmental Working Group	Direct Testimony - Low-income affordability program, credit and collections data reporting	Indiana	Oct-19
D.P.U. 18-150 - National Grid	Massachusetts Energy Directors Association	Direct Testimony - Transportation Electrification, Rate Design	Massachusetts	Mar-19
Docket No. 2018-318-E - Duke Energy Progress	Southern Environmental Law Center, NAACP, South Carolina Coastal Conservation League	Direct Testimony - Rate design, low-income energy efficiency and affordability programs	South Carolina	Mar-19
Cause No. 45159 - Northern Indiana Public Service Company	Citizens Action Coalition of Indiana	Direct Testimony - Rate design, low-income affordability program, credit and collections data reporting	Indiana	Feb-19
Docket No. 2018-319-E - Duke Energy Carolinas	Southern Environmental Law Center, NAACP, South Carolina Coastal Conservation League	Direct Testimony - Rate design, low-income energy efficiency and affordability programs	South Carolina	Feb-19
Docket No. 18-1008/1009 - Ameren Illinois Company	Illinois Attorney General's Office	Rebuttal Testimony - Prepaid utility service	Illinois	Nov-18
Docket No. 18-1008/1009 - Ameren Illinois Company	Illinois Attorney General's Office	Direct Testimony - Prepaid utility service	Illinois	Sep-18
D.P.U. 18-40 - The Berkshire Gas Company	Massachusetts Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association	Direct Testimony - General rate case, low-income discount rate	Massachusetts	Sep-18

D.P.U. 18-45 - Bay State Gas Company d/b/a Columbia Gas of Massachusetts	Massachusetts Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association	Direct Testimony - General rate case, low-income discount rate	Massachusetts	Aug-18
Case No. 18-00043-UT - Public Service Company of New Mexico	New Mexico Coalition for Clean Affordable Energy	Direct Testimony - Rate design	New Mexico	Aug-18
Cause No. 45029 - Indianapolis Power & Light Company	Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, Sierra Club	Direct Testimony - Rate design	Indiana	May-18
Docket No. 17-0837 - Commonwealth Edison Company	Illinois Attorney General's Office	Direct Testimony - Prepaid utility service	Illinois	Mar-18
D.P.U. 17-170 - Boston Gas Company, Colonial Gas Company, each d/b/a National Grid	Massachusetts Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association	Direct Testimony - General rate case, low-income discount rate	Massachusetts	Mar-18
Docket No. E-7, Sub 1146 - Duke Energy Carolinas	Southern Environmental Law Center, North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy	Direct Testimony - General rate case, rate design, affordable payment program	North Carolina	Jan-18
Cause No. 44967 - Indiana Michigan Power Company	Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, Sierra Club	Direct Testimony - Rate design, affordable payment program	Indiana	Nov-17
Docket No. E-2, Sub 1142 - Duke Energy Progress	Southern Environmental Law Center, North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy	Direct Testimony - General rate case, rate design, affordable payment program	North Carolina	Oct-17

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Docket No. P-2016-2572033 - RECO Energy Company's plan for an advanced payments program and petition for waiver of a portion of the Commission's regulations	Pennsylvania Office of Consumer Advocate	Surrebuttal Testimony - Prepaid utility service	Pennsylvania	Aug-17
Docket No. P-2016-2572033 - RECO Energy Company's plan for an advanced payments program and petition for waiver of a portion of the Commission's regulations	Pennsylvania Office of Consumer Advocate	Rebuttal Testimony - Prepaid utility service	Pennsylvania	Jul-17
Docket No. P-2016-2572033 - RECO Energy Company's plan for an advanced payments program and petition for waiver of a portion of the Commission's regulations	Pennsylvania Office of Consumer Advocate	Direct Testimony - Prepaid utility service	Pennsylvania	Jun-17
D.P.U 15-155 - Massachusetts Electric Company, Nantucket Electric Company, each d/b/a National Grid	Massachusetts Low-Income Weatherization and Fuel Assistance Program Network	Direct Testimony - low-income discount rate, rate design, net energy metering and solar renewable energy credits	Massachusetts	Mar-16
Cause No. 44688 - Northern Indiana Public Service Company	Citizens Actions Coalition of Indiana and the Environmental Law & Policy Center	Direct Testimony - General rate case - rate design, affordability program, credit and collections data reporting	Indiana	Jan-16
Case No. 15-00261-UT - Public Service Company of New Mexico	New Mexico Coalition for Clean Affordable Energy	Direct Testimony - Rate design, affordable payment program, credit and collections data collection and reporting	New Mexico	Jan-16
6690-UR-124 - Wisconsin Public Service Corporation	Wisconsin Community Action Program Association	Comment - Rate design	Wisconsin	Oct-15

Cause No. 44576 - Indianapolis Power and Light Company	Citizens Actions Coalition of Indiana, Indiana Association for Community and Economic Development, Indiana Coalition of Human Services, Indiana Community Action Association, Indiana NAACP, and National Association of Social Workers Indiana Chapter	Direct Testimony - energy affordability program, rate design	Indiana	Jul-15
05-UR-107 - Wisconsin Electric Power Company and Wisconsin Gas Company	Wisconsin Community Action Program Association	Comment - Rate design	Wisconsin	Oct-14
3270-UR-120 - Madison Gas and Electric Company	Wisconsin Community Action Program Association	Comment - Rate design	Wisconsin	Oct-14
6690-UR-123 - Wisconsin Public Service Corporation	Wisconsin Community Action Program Association	Comment - Rate design	Wisconsin	Sep-14
Docket 14-05004 - Nevada Energy Company	Nevada Bureau of Consumer Protection	Direct Testimony - Prepaid utility service	Nevada	Aug-14
D.P.U. 14-04 - Investigation into time-varying rates	NCLC's low-income clients	Comment - Rate design, regulatory consumer protections	Massachusetts	Mar-14
Docket No. 4450 - Rules and regulations governing the termination of residential electric and natural gas service	George Wiley Center	Comment - Regulatory consumer protections	Rhode Island	Dec-13
Application 11-10-002 - San Diego Gas and Electric Company For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design	National Consumer Law Center's low-income clients, The Utility Reform Network, Center for Accessible Technology, Greenlining Institute	Direct Testimony - Prepaid utility service	California	Jun-12
Rulemaking 09-11-014 - Rulemaking to Examine the Commission’s Post-2008 Energy Efficiency Policies, Programs, Evaluation, Measurement, and Verification, and Related Issues	NCLC's low-income clients	Comment - Energy efficiency financing	California	Feb-12

Rulemaking 09-11-014 - Rulemaking to Examine the Commission's Post-2008 Energy Efficiency Policies, Programs, Evaluation, Measurement, and Verification, and Related Issues	NCLC's low-income clients	Reply Comment - Energy efficiency financing	California	Feb-12
Docket Nos. UE-111048 and UG-111049 - Puget Sound Energy	The Opportunity Council	Direct Testimony - Bill payment assistance, home energy affordability	Washington	Dec-11
R-10-02-005 - Rulemaking to address the issue of customers' electric and natural gas service disconnection	NCLC's low-income clients	Comments - Regulatory consumer protections	California	Sep-10
Docket No. 7535 - Petition of AARP for the establishment of reduced rates for low-income consumers of Green Mountain Power Corporation and Central Vermont Public Service Corporation; and as expanded to possibly include general applicability to all Vermont retail electric utilities	AARP Vermont	Rebuttal Testimony - Bill payment assistance	Vermont	Jun-10
Docket 10-02009 - Nevada Energy	Washoe County Senior Law Project	Direct Testimony - Advanced meter consumer protections	Nevada	Apr-10

R-10-02-005 - Rulemaking to address the issue of customers' electric and natural gas service disconnection	NCLC's low-income clients	Opening Comment - Regulatory consumer protections	California	Mar-10
Docket No. 06-0703 - Rulemaking IL Admin. Code - Part 280	South Austin Community Council and Community Action for Fair Utility Practice	Direct Testimony - Regulatory consumer protections	Illinois	Jan-10
Project No. 35533	NCLC's low-income clients	Comment - Prepaid utility service	Texas	Jan-10
Cause No. 43669 - Citizens Gas, Northern Indiana Public Service Company, and Vectren Energy Delivery	AARP and Citizens Action Coalition	Direct Testimony - Bill payment assistance, home energy affordability	Indiana	Sep-09
Docket No. 7535 - Petition of AARP for the establishment of reduced rates for low-income consumers of Green Mountain Power Corporation and Central Vermont Public Service Corporation; and as expanded to possibly include general applicability to all Vermont retail electric utilities	AARP Vermont	Direct Testimony - Bill payment assistance	Vermont	Sep-09
D.P.U. 09-34 - Western Massachusetts Electric Company	Low Income Weatherization and Fuel Assistance Network	Comment - Prepaid utility service	Massachusetts	Jun-09
Case No. ER-2008-0318 - Ameren UE	AARP	Surrebuttal Testimony - Hot weather safety program	Missouri	Nov-08
Case No. ER-2008-0318 - Ameren UE	AARP	Direct Testimony - Hot weather safety program	Missouri	Aug-08
D.T.E./D.P.U. 07-30 - Petition of the Attorney General for an Oversight Investigation of the Proposed Merger of National Grid and Keyspan	Low-Income Weatherization and Fuel Assistance Program Network and Massachusetts Energy Directors Association	Supplemental Direct Testimony - Customer service and regulatory consumer protections	Massachusetts	Nov-07

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D.T.E./D.P.U. 07-30 - Petition of the Attorney General for an Oversight Investigation of the Proposed Merger of National Grid and Keyspan	Low-Income Weatherization and Fuel Assistance Program Network and Massachusetts Energy Directors Association	Direct Testimony - Customer service and regulatory consumer protections	Massachusetts	Nov-07
CASE NO. PAC- 07-5 - Rocky Mountain Power	Community Action Partnership of Idaho	Direct Testimony - Collection agency costs, credit and collection rules	Idaho	Sep-07
Docket No. P- 00062240 - Equitable Gas company for Approval to Increase the Level of Funding for its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	Pennsylvania Utility Law Project	Surrebuttal Testimony - Low Income affordability programs	Pennsylvania	May-07
Docket No. P- 00062240 - Equitable Gas company for Approval to Increase the Level of Funding for its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	Pennsylvania Utility Law Project	Rebuttal Testimony - Low Income affordability programs	Pennsylvania	May-07
Docket No. P- 00062240 - Equitable Gas company for Approval to Increase the Level of Funding for its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	Pennsylvania Utility Law Project	Direct Testimony - Low Income affordability programs	Pennsylvania	Apr-07

Project No. 33814 - Rulemaking concerning prepaid retail electric service	AARP	Reply Comment - Prepaid electric service	Texas	Mar-07
Docket No. D-06-13 - Petition of Narragansett Electric Company and Southern Union Gas Company for Purchase and Sale of Assets	George Wiley Center	Direct Testimony - Merger impact mitigation	Rhode Island	Jun-06
Docket No. 06-0202 - Petition to Initiate Rulemaking with Notice and Comment for Approval of Certain Amendments to Illinois Administrative Code Part 280	South Austin Community Council and Community Action for Fair Utility Practice	Direct Testimony - Regulatory consumer protections	Illinois	Apr-06
Docket No. 3696 - New England Gas Company	George Wiley Center	Direct Testimony - General rate case - mitigation of low-income rate and bill impacts	Rhode Island	Oct-05
Docket 05-0237 - Petition to Initiate Rulemaking with Notice and Comment for Approval of Certain Amendments to Illinois Administrative Code Part 280	South Austin Community Council and Community Action for Fair Utility Practice	Direct Testimony - Regulatory consumer protections	Illinois	Jun-05
Docket No. 04-5003 - Nevada Power Company	Nevada Bureau of Consumer Protection	Direct Testimony - Prepaid utility service	Nevada	Jun-04
Docket No. R-00049255 - PPL Universal Service Programs	Commission on Economic Opportunity	Direct Testimony - Universal service programs	Pennsylvania	Jun-04
Docket No. UD-97-5 - Entergy New Orleans' and Entergy Louisiana's Electric and Natural Gas Service Regulations, Policies and Standards	Alliance for Affordable Energy, Louisiana Environmental Action Network, League of Women Voters of New Orleans, Pax Christi, and Bread for the World	Direct Testimony - Regulatory consumer protections	New Orleans City Council	Jul-00

Exhibit JH-2

Duke Energy Progress
Response to
NCJC Data Request
Data Request No. 8

Docket No. E-2, Sub 1219

Date of Request: February 28, 2020
Date of Response: March 6, 2020

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 8-2, was provided to me by the following individual(s): Conitsha Barnes, Regulatory Affairs Manager, and was provided to NCJC under my supervision.

Camal O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

8-2. For each 5-digit zip code identified in 7-1 above, please provide the following:
a. The average number of residential customers served during the most recent 36-month period,
b. The dollar value of billing of residential customers during the most recent 36-month period,
c. The number of residential accounts charged a late payment fee or charge each month during the most recent 36-month period,
d. The dollar value of residential late payment charges each month during the most recent 36-month period,
e. The number of disconnection for nonpayment notices sent to residential customers each month during the most recent 36-month period,
f. The number of residential accounts written off as uncollectible each month during the most recent 36-month period,
g. The number of residential accounts more than 60 days in arrears during the most recent 36-month period,
h. The dollar value of residential accounts more than 60 days in arrears during the most recent 36-month period,
i. The number of residential accounts written off as uncollectible during the most recent 36-month period,
j. The dollar value of residential account write-offs each month during the most recent 36-month period, and
k. The number of residential disconnections for non-payment during the most recent 36-month period.

Response:

Duke Energy does not track customer data by zip code or census track in its billing system.

However, please review NCUC Docket No. M-100, Sub 61A for the number of residential non-pay disconnects by month.

8-2.A The average number of residential customers served during the most recent 36-month period,
8-2.B The dollar value of billing of residential customers during the most recent 36-month period,

Month	#	$
Feb-20	1,207,179	$172,739,764
Jan-20	1,206,596	$178,499,930
Dec-19	1,211,655	$178,514,250
Nov-19	1,212,404	$134,418,941
Oct-19	1,212,120	$161,244,242
Sep-19	1,215,125	$194,325,224
Aug-19	1,218,468	$212,174,035
Jul-19	1,217,065	$211,029,668
Jun-19	1,220,921	$172,255,268
May-19	1,220,028	$143,602,163
Apr-19	1,223,487	$142,957,465
Mar-19	1,224,704	$159,939,885
Feb-19	1,225,246	$196,745,528
Jan-19	1,228,589	$197,025,785
Dec-18	1,188,213	$184,891,753
Nov-18	1,183,708	$158,658,775
Oct-18	1,179,733	$163,835,875
Sep-18	1,182,452	$177,161,647
Aug-18	1,173,833	$195,623,330
Jul-18	1,169,991	$197,704,157
Jun-18	1,171,294	$171,604,530
May-18	1,171,868	$128,628,008
Apr-18	1,168,357	$139,797,236
Mar-18	1,169,478	$102,418,106

8-2.C The number of residential accounts charged a late payment fee or charge each month during the
8-2.D The dollar value of residential late payment charges each month during the most recent 36-mont

Month	#	S	
Feb-20	258,515	$522,229	
Jan-20	271,374	$535,278	
Dec-19	309,646	$556,150	
Nov-19	267,551	$455,862	
Oct-19	300,636	$674,802	
Sep-19	277,197	$623,121	
Aug-19	289,399	$614,638	
Jul-19	294,535	$595,914	
Jun-19	241,811	$395,400	
May-19	264,213	$447,288	
Apr-19	302,943	$668,311	
Mar-19	253,211	$568,928	
Feb-19	276,856	$643,861	
Jan-19	271,373	$535,277	
Dec-18	266,408	$434,206	
Nov-18	187,809	$320,946	
Oct-18	30,799	$50,652	* Oct. 11 - Dec. 31, 2018, late payment charges surpressed for Easter
Sep-18	153,885	$311,640	
Aug-18	296,731	$614,218	
Jul-18	297,101	$572,492	
Jun-18	256,593	$397,603	
May-18	293,579	$518,191	
Apr-18	272,163	$473,484	
Mar-18	267,436	$551,241	

most recent 36-month period,
h period,

'n and Southern Regions, due to Hurrican Matthew

8-2.E The number of disconnection for nonpayment notices sent to residential customers each month c

Month	#
Feb-20	164086
Jan-20	172739
Dec-19	168,638
Nov-19	176,943
Oct-19	193,940
Sep-19	174,318
Aug-19	175,314
Jul-19	176,796
Jun-19	156,524
May-19	174,080
Apr-19	175,219
Mar-19	176,437
Feb-19	164,571
Jan-19	172,738
Dec-18	165,260
Nov-18	186,889
Oct-18	194,033
Sep-18	175,508
Aug-18	186,827
Jul-18	170,899
Jun-18	160,696
May-18	166,426
Apr-18	161,569
Mar-18	174,406

during the most recent 36-month period,

8-2.F The number of residential accounts written off as uncollectible each month during the most recent 36-mon
8-2.J The dollar value of residential account write-offs each month during the most recent 36-month period,

Month	#	$
Feb-20	2858	592677.32
Jan-20	3888	905377.03
Dec-19	3,784	$924,854
Nov-19	4,356	$1,143,955
Oct-19	4,252	$1,087,728
Sep-19	3,191	$820,876
Aug-19	3,343	$915,509
Jul-19	3,339	$1,145,450
Jun-19	3,649	$1,349,314
May-19	3,524	$1,196,867
Apr-19	3,490	$1,040,444
Mar-19	2,948	$761,756
Feb-19	3,672	$951,449
Jan-19	3,888	$905,197
Dec-18	2,985	$737,549
Nov-18	4,195	$955,395
Oct-18	3,868	$804,291
Sep-18	3,429	$740,062
Aug-18	3,282	$764,287
Jul-18	3,438	$988,585
Jun-18	3,501	$1,023,500
May-18	3,492	$1,073,226
Apr-18	2,917	$683,588
Mar-18	2,627	$505,877

th period,

EXHIBIT JH-3

Public Utilities Commission

Energy Assistance Resource Guide

2019–2020

- PIPP Plus
- Graduate PIPP Plus
- Winter Reconnect Order
- Energy Assistance Programs
- Payment Plans
- Disconnect and Reconnect Procedures

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GENERAL PIPP PLUS INFORMATION

1. What is PIPP Plus?

The Percentage of Income Payment Plan or PIPP Plus is an extended payment arrangement that requires regulated gas and electric companies to accept payments based on a percentage of the household income for those customers who are at or below 150% of the federal income guidelines. The PIPP Plus payment amount is based on the household's countable income received during the previous 30 days.

- If a gas customer qualifies for PIPP Plus, he or she would pay 6% of the household's current gross monthly income to the gas company or a minimum of ten dollars, whichever is greater, year-round.
- If electricity is not the primary heat source, a customer pays 6% of the household's current gross monthly income to the electric company or a minimum of ten dollars, whichever is greater, year-round.
- The customer of an all-electric household pays 10% of the household's monthly income or a minimum of ten dollars, whichever is greater, year-round.
- A customer served by Duke who has a gas heating account and an electric baseload account would pay 12% (6% gas, 6% electric) of the monthly household income or $10 per utility whichever is greater, year-round.
- A customer served by Duke Energy with an all electric home will pay 10% of the monthly household income or $10, whichever is greater, year-round.

The Development Services Agency (ODSA), Office of Community Assistance (OCA), administers PIPP Plus for electric customers statewide. The Public Utilities Commission of Ohio (PUCO) created the PIPP Plus gas rules in PUCO case number 08-723-AU-ORD. Development created electric PIPP Plus rules in Chapter 122:5-3, Ohio Administrative Code (O.A.C.).

A PIPP Plus customer is also required to apply for all public energy assistance and weatherization programs for which he/she is eligible. PIPP Plus customers must apply for the regular Home Energy Assistance Program (HEAP) and the Home Weatherization Assistance Program (HWAP).

2. How does one qualify for PIPP Plus?

In order to qualify for PIPP Plus, a customer must:

(A) Receive his or her gas heat or electric service from a company regulated by the PUCO;

(B) Apply for all energy assistance and weatherization programs for which he or she is eligible; and

(C) Have a total household income which is at or below 150% of the federal income guidelines.

PIPP PLUS INCOME GUIDELINES
150% Federal Income Guidelines 2019-2020

SIZE OF HOUSEHOLD	12-Month Income Limit	30-Day Income Limit
1- Person	$ 18,735.00	$ 1,539.86
2- Persons	$ 25,365.00	$ 2,084.79
3- Persons	$ 31,995.00	$ 2,629.73
4- Persons	$ 38,625.00	$ 3,174.66
5- Persons	$ 45,255.00	$ 3,719.59
6- Persons	$ 51,885.00	$ 4,264.52

Households with more than six members add $544.93 or $6,630/yr. for each additional member.

Winter Crisis and Regular HEAP Income Guidelines
175% Federal Income Guidelines 2019-2020

SIZE OF HOUSEHOLD	12-Month Income Limit	30-Day Income Limit
1- Person	$ 21,857.50	$ 1,796.51
2-Persons	$ 29,592.50	$ 2,432.26
3- Persons	$ 37,327.50	$ 3,068.01
4- Persons	$ 45,062.50	$ 3,703.77
5- Persons	$ 52,797.50	$ 4,339.52
6- Persons	$ 60,532.50	$ 5,611.03

Households with more than six members add $635 or $7,735/yr. for each additional member.

3. Heating sources

Rule 122:5-3-01, O.A.C.

- "Electrically heated" residence means a residence for which the primary source of heating is an electric appliance such as an electric furnace, heat pump, or electric baseboard heater.

- Electric "baseload" means a residence for which electricity is not the primary source of heat.

Rule 4901:1-18-13(A) (1), O.A.C.

Gas PIPP Plus is only available to customers who heat with natural gas. (The Duke Energy Ohio hybrid plan is an exception to this statement.)

Examples

If a customer has a gas furnace with an electric thermostat or blower, the primary source of heat would be gas and the electric service is considered baseload. The customer would pay a monthly installment based on 6% of the household income for gas service and a monthly installment based on 6% of the household income for electric service.

If a customer has both natural gas space heaters and electric space heaters, but the natural gas heaters are used to heat the largest portion of the residence, the primary source of heat would be gas. The customer would pay a monthly installment based on 6% or a minimum of $10, (whichever is greater) of the household income for gas service and a monthly installment based on 6% of the household income for electric service.

A customer has an unregulated source of heat (fuel oil, propane, wood, electric co-op) and a regulated source of heat which is used to heat the largest portion of the residence. This customer receives regular HEAP benefits for the regulated source of heat. In that instance, the customer is eligible for PIPP Plus for the regulated utility. The customer would pay a monthly installment based on 6% or a minimum of $10, (whichever is greater) of the household income, or a minimum of $10, whichever is greater for the regulated source of heat.

4. How does a customer sign up for PIPP Plus?

- Individuals who are applying for PIPP Plus for the first time must go to the local HEAP Agency.
- Customers who need to reverify their household income and size can do so the following ways:
- Online at www.energyhelp.ohio.gov
- Download and complete an Energy Assistance application by going to www.development.ohio.gov
  Mail completed applications with documentation to:
  Ohio Development Services Agency
  P. O. Box 1240
  Columbus, OH 43216
- If applying by mail, customers must submit proof of income documentation as required by ODSA (See Appendix B for income documentation).
- Mailed applications will not be accepted for first time PIPP Plus enrollees.
- Mailed applications will not be accepted for households claiming zero income. All applicants who claim zero income must apply for assistance in person at the local HEAP agency.
- For the mail-in application process, companies may also require that every adult member of the household sign a statement affirming that the information on the application is true and giving the company permission to verify the information provided.
- The customer must also apply for all energy assistance and weatherization programs for which he or she is eligible.

5. **What is the percentage of income amount paid by a natural gas customer?**

PIPP Plus customers who use natural gas to heat the largest portion of their residence will pay 6% of their monthly household income or $10, whichever is greater, year-round.

6. **What is the percentage of income amount paid by an electric customer?**

PIPP Plus customers who use electric as baseload will pay 6% of their monthly household income or $10, whichever is greater, year-round.

PIPP Plus customers who use electric as their primary heating source will pay 10% of their monthly household income or $10, whichever is greater year-round.

7. **What is the minimum amount that a customer can pay on PIPP Plus?**

A customer who is determined zero income must pay a $10 minimum installment. **All applicants who claim zero income** must apply for assistance in person at the local HEAP agency.

8. **What if the household income or size changes?**

The customer must report income changes to the local HEAP provider or OCA within 30 days. If the household income decreases, this will lower the PIPP Plus installment amount. If the household income increases, the customer's PIPP Plus installment amount will increase. Electric and gas companies must accept the income as reported by OCA.

9. **What if the household's income rises above 150% of the federal income guidelines?**

If the household's income rises above 150% of the federal income guidelines, the customer becomes ineligible for PIPP Plus. Graduate PIPP Plus is available to customers who are no longer income eligible for PIPP Plus. The customer must be current with PIPP Plus installments to join Graduate PIPP Plus; therefore, the customer has one billing cycle to make up missed PIPP Plus payments (the grace period). The customer’s eligibility begins no later than the end of the grace period. **(See Graduate PIPP Plus Section).**

10. What are the benefits of PIPP Plus?

- PIPP Plus customer bills will be adjusted for the difference between the required installment payment and the current month's utility charges.
- Customers will earn 1/24th credit on the arrearage for on-time and in-full payments.
- No deposit or late fees will be applied to the account.

11. When can a customer enroll on PIPP Plus?

Customers may enroll on PIPP Plus at any time. However, before enrolling on PIPP Plus, the customer must have utility service in his/her name. The customer must then meet the income guidelines for PIPP Plus.

12. When is the first PIPP Plus installment due?

The first PIPP Plus installment is owed to the company by the due date of the current bill. If the due date of the current bill has passed and the customer has not made a payment the customer will be required to make two installment payments by the due date of the next bill (one installment will be applied to the past due bill, and one installment will cover the current installment amount due).

13. What is considered an on-time payment?

For the purpose of applying incentive credits, the PIPP Plus installment payment must be received by the utility company prior to the date that the next bill is issued.

14. What happens if the PIPP Plus installment is not received by the due date?

If the installment payment is not received before the next month's bill is issued; the customer is not eligible to receive the incentive credit (the difference between the required installment payment and the current month's utility charges). Also, the customer will not receive the 1/24th credit for the month.

15. If a customer makes multiple payments in one billing cycle equal to the amount of the PIPP Plus installment, will the customer receive an arrearage credit?

Yes, as long as the total of all payments made during the billing cycle equal the PIPP Plus installment and is paid prior to the date that the next bill is issued.

16. Will the utility company change the due date for the customer?

No, the utility company is not obligated to change the due date for a customer; some utility companies **may be** willing to adjust the due date so customers can meet their payment obligations and receive credits.

17. May the utility company charge a PIPP Plus customer a security deposit?

Utilities are **not** permitted to charge PIPP Plus customers a security deposit. Any deposit paid by a customer prior to enrolling in PIPP Plus shall be credited to the customer's outstanding arrearage.

18. How much does an income eligible PIPP Plus customer with an arrearage have to pay to get service at a <u>new</u> address if the most recent PIPP Plus account has been finalized?

The customer will be required to pay <u>any</u> missed payments (which may include actual bill charges), including previous PIPP Plus installments which would have been due for the months the customer is disconnected from service. The amount owed shall not exceed the amount of the customer's arrearages.

During the winter heating season, PIPP Plus customers may utilize the winter reconnect order to have service restored for a maximum of $175.00. **(See Special Reconnection Procedures).**

19. If a customer is on another type of payment plan, is he or she still eligible for PIPP Plus?

Yes, if the customer meets the eligibility requirements of PIPP Plus, he or she may enroll on PIPP Plus at any time. The customer will not be required to complete the terms of the previous payment arrangement or be current on the previous arrangement to go on PIPP Plus. If the customer has PIPP Plus default, the PIPP Plus default needs to be paid prior to re-enrolling on PIPP Plus.

20. May the company pursue collections from the PIPP Plus customer for his or her arrearages?

Yes, the arrearages are a legal debt. The company may use any standard means of collection after a judgment is obtained from a court, such as the garnishment of wages or the placing of a lien on the customer's property. The company may also turn the debt over to a collection agency. The company may ***not*** disconnect service to collect the arrearage as long as the customer remains current on the PIPP Plus plan.

21. If a customer overpays his or her PIPP Plus installment one month, will it be credited to the next month's payment?

Gas: No, any overpayments of installments are used to offset the arrearage balance. Gas utilities may review any overpayments made by a customer on a case by case basis and may apply the overpayment toward a future installment as a courtesy.

Electric: Yes, any overpayments of installments are applied to future installments once any missed installments have been cured. An overpayment made by the customer will be eligible for an incentive credit for the month. **(Duke will follow the electric practice.)**

22. Can the company refuse to transfer service if the customer has a PIPP Plus default?

Yes, the customer must cure any PIPP Plus default (customer is not required to pay the entire account balance) in order to transfer service. If the customer has reverified his/her income within the last 12 months and the installments are current, the PIPP Plus account balance shall transfer to the new address.

23. Does a customer have to go on PIPP Plus for both gas and electric service if the customer needs the plan for only one of them?

No, a customer may elect to go on PIPP Plus for gas or electric or both. Gas PIPP Plus is only available to customers who heat with natural gas.

24. Are gas and electric companies regulated by the PUCO the only companies required to offer PIPP Plus?

Yes, only companies regulated by the Commission are required to offer PIPP Plus. Non-regulated utilities may offer PIPP Plus, but they are not required by law to do so. (Some small gas companies may continue to offer the old PIPP Plan. (**See Appendix C for details).**

25. Are PIPP Plus customers allowed to choose a Certified Retail <u>Natural Gas</u> Supplier (CRNGS) or Certified Retail <u>Electric</u> Supplier (CRES)?

No, PIPP Plus customers can not choose a supplier (CRNGS, CRES) on an individual basis.

26. Are PIPP Plus customers eligible for a governmental aggregation program?

No, PIPP Plus customers must continue to pay the installment amount based upon the total household income as determined by the HEAP Provider or OCA, however PIPP Plus customers will see overall lower bills, which will reduce their total arrearages.

27. What happens if a customer who is with a supplier (CRNGS or CRES) wants to enroll in PIPP Plus?

When the HEAP Provider enrolls a customer in PIPP Plus and notifies the electric distribution utility (EDU) or the local distribution company (LDC) of the enrollment, the utility will then notify the supplier of the change. However, it is strongly advised that the customer also notify the supplier of the change. The change will take place within one or two billing cycles after the EDU/LDC enrolls the customer in PIPP Plus.

Note: The supplier may charge a cancellation fee if allowed per contract.

28. Can a customer who is with a supplier (CRNGS or CRES) receive energy assistance?

Yes, customers who are with a supplier but meet the income eligibility guidelines can still receive energy assistance (WCP, SCP, HEAP, and fuel funds). Energy assistance payments will go to the regulated utility company to be applied to the customer's account.

CREDIT BALANCE

29. What happens if a PIPP Plus or Graduate PIPP Plus customer's account becomes a credit balance?

In order to remain on PIPP Plus or Graduate PIPP Plus the customer must continue to make his/her installment payments.

30. Will the customer earn incentive credits if there is a credit balance on the account?

No, the customer will no longer earn incentive credits until the account balance is no longer a credit. The difference between the current usage and the installment is reduced from the credit balance.

31. Can the credit balance be used in lieu of making installment payments?

No, if the customer would like to remain on PIPP Plus or Graduate PIPP Plus he/she must make the required installment payments.

32. Can the customer request a refund of the credit balance?

Yes, the customer can request a refund of the credit balance. The utility company will review the account to ensure that the credit balance is not a result of incentive credits. If the credit balance is not a result of incentive credits, the customer will be eligible for a refund. In order to receive a refund of the credit balance the account will be removed from PIPP Plus. The utility company should inform the customer of the availability of a more suitable payment plan option. (**See PIPP Plus Re-enrollment Section**).

33. Does the account have to be removed from PIPP Plus if the customer requests a refund of the credit balance?

Yes, if the customer requests a refund of the credit balance, the company will remove the account from PIPP Plus. **(See PIPP Plus Re-enrollment Section**)

34. Can the customer re-enroll on PIPP Plus after the credit balance has been refunded?

Yes, as long as the customer meets the income guidelines for PIPP Plus he/she can re-enroll on PIPP Plus. However, if the customer re-enrolls on PIPP Plus within 12-months he/she will be required to make up installment payments. **Please see PIPP Plus Re-enrollment Section.**

GRADUATE PIPP PLUS and POST PIPP PLUS

35. What is Graduate PIPP Plus?

Graduate PIPP Plus allows customers who are no longer eligible to participate in PIPP Plus as a result of an increase in the household income or a change in the household size to continue to receive a reduction in their outstanding arrearages in return for making timely payments. PIPP Plus customers who choose to no longer participate in PIPP Plus can also join Graduate PIPP Plus. Customers must be current on all PIPP Plus payments to enroll in Graduate PIPP Plus. **Graduate PIPP Plus is a 12-month payment plan.**

36. What are the benefits of Graduate PIPP Plus?

- Graduate PIPP Plus customers will receive arrearage reduction for on-time and in-full payments.
- Customer will earn 1/12th credit on the arrearage.
- Graduate PIPP Plus customer bills will be adjusted for the difference between the required installment payment and the current month's utility charges.
- No deposit or late fees will be applied to the account.

37. How much is a Graduate PIPP Plus customer required to pay?

Graduate PIPP Plus customers will be placed on a Transition Installment Amount (TIA). The TIA payment is based on the customer's most recent PIPP Plus installment plus a budget plan amount (established by the utility company) divided by two.

Example: $ 30 (PIPP Plus installment)
$ 110 (Budget Plan Amount)
$ 140/2 = $70 (Monthly Graduate PIPP Plus installment (TIA))

38. How does a customer enroll on Graduate PIPP Plus?

A customer who is income ineligible (or no longer wishes to participate) and has an arrearage will automatically be enrolled (via a nightly file sent from OCA to the utility company) on Graduate PIPP Plus at the time of reverification. A customer must be current on all PIPP Plus payments to enroll in Graduate PIPP Plus. Customers who are not current with PIPP Plus payments will have one billing cycle to make up any missed PIPP Plus payments; otherwise he/she will be removed from the Graduate PIPP Plus program.

39. What happens if the customer does not make up the required PIPP Plus payments within one billing cycle to enroll in Graduate PIPP Plus?

A customer can enroll in Graduate PIPP Plus within 12 months from being removed from PIPP Plus. The customer must pay any defaulted PIPP Plus installments and current bills for the months the customer received service but was not on Graduate PIPP Plus (less any payments made by the customer after being dropped.

40. Does a customer have to be income ineligible for PIPP Plus to enroll in Graduate PIPP Plus?

No, a customer may elect to terminate participation in PIPP Plus and enroll in Graduate PIPP Plus at any time. However, customers must be current on all PIPP Plus payments to enroll in Graduate PIPP Plus. The customer must contact the utility company to enroll.

41. What is the maximum amount of time a customer can remain on Graduate PIPP Plus?

Graduate PIPP Plus is offered for a period of 12 months that begins when the customer is removed from PIPP Plus due to being over income or when the customer voluntarily removes themselves from PIPP Plus.

42. Is a customer eligible for Graduate PIPP Plus if he/she moves outside of the company's service territory?

No, in order to be eligible for Graduate PIPP Plus, the customer must remain a customer of the same utility in which he/she was enrolled in PIPP Plus. **(See Post PIPP Plus question 46**).

43. How can a customer who has been removed from Graduate PIPP Plus for non-payment get reinstated?

The customer must make up any missed graduate PIPP Plus payments to get reinstated on graduate PIPP Plus. Graduate PIPP Plus ends 12 months from the date of the customer's initial enrollment on Graduate PIPP Plus. At the end of twelve months the customer can enroll on an extended payment for the remaining arrearages. **(See question 123 for extended payment plan).**

44. Can a Graduate PIPP Plus customer choose a supplier (CRNGS or CRES)?

No, Graduate PIPP Plus customers can not choose a supplier (CRNGS, CRES) on an individual basis. Graduate PIPP Plus accounts remain as part of the PIPP Plus pool. **(See question 25).**

45. How much does a PIPP Plus/Graduate PIPP Plus customer have to pay if he/she moves out of the utility company's service territory or no longer need utility service?

Customers who are currently enrolled on PIPP Plus or Graduate PIPP Plus and owe an arrearage are eligible for Post PIPP Plus if they move out of the service territory or no longer need utility service in their name. **(See question 46).**

46. What is Post PIPP Plus?

Post PIPP Plus is a 12 month payment plan for former PIPP Plus or former Graduate PIPP Plus customers who are no longer customers of the utility but still have an arrearage. Post PIPP Plus is only available in the 12 months immediately after a PIPP Plus account is closed. Post PIPP Plus is offered by electric and gas companies.

47. Who is eligible for Post PIPP Plus?

PIPP Plus or Graduate PIPP customers who contact the utility company to close their account for the following reason(s):

a. Moving beyond the utility companies service territory

b. Transferring to a residence where utility service is not in the former PIPP Plus or Graduate PIPP Plus customer's name.

c. Moving to a master-metered residence.

48. How does a customer enroll on Post PIPP?

The utility company may offer Post PIPP on the final bill or the company may automatically enroll a customer on Post PIPP when contacted by the customer to close his/her account. **(See question 46).**

49. How much does a customer pay on Post PIPP?

The customer enters into a payment plan to pay at least 1/60th of the finaled account arrears for 12 months. For each payment made, the utility will credit 1/12th of the customer's arrears.

Example: A customer whose total arrearage is $2400 would be required to make a minimum payment of $40 each month (1/60th payment equals $2400/60=$40). Arrearage credit adjustment on outstanding debt is $200 (1/12th arrearage credit equals $2400/12=$200). At the end of 12 months, the outstanding debt will be credited.

50. Does the customer have to be current with PIPP Plus or Graduate PIPP Plus payments to enroll on Post PIPP Plus?

Yes, customers are required to be current (in good standing) with his/her PIPP Plus or Graduate PIPP Plus installments in order to enroll on Post PIPP Plus.

51. How long does a customer have to enroll on Post PIPP Plus?

Customers can join Post PIPP Plus within 12 months from when the account is finaled. The time period is not extended if the customer does not join or bring the account current right away.

52. Can a customer be enrolled on Post PIPP and PIPP Plus at the same time?

Yes, a customer can be enrolled on Post PIPP Plus with the former utility and enroll on PIPP Plus (must be income eligible) with the new utility company.

53. Is the former utility company required to send a bill each month?

The former utility company is <u>not required</u> to send a monthly bill to customers who are enrolled on Post PIPP Plus. However, some utility companies may provide a monthly statement. Customers should discuss the terms of Post PIPP Plus with the utility company.

APPLICATION PROCESS

In order for a person to qualify for the Percentage of Income Plan Plus (PIPP), he/she must 1) be a customer of a regulated gas or electric utility, 2) be income eligible, and 3) apply for all public energy and weatherization assistance programs for which the household is eligible.

54. What is the difference between a customer and a consumer?

A ***customer*** is any person who enters a contractual agreement with the company to receive electric or gas service. A ***consumer*** is any person who is the ultimate user of electric or gas service. In other words, a customer has the account in his or her name.

55. May the company require that the PIPP Plus applicant also be the household member with income?

No, provided the PIPP Plus applicant is a household member, he or she need not provide a source of income to the household.

56. May a PIPP Plus customer have more than one account?

Yes, a customer may have an account at a different location; however, only **one** account may be a PIPP Plus account. The PIPP Plus account must be at the primary residence.

57. What happens if a PIPP Plus customer is determined to be fraudulently enrolled in PIPP Plus?

The utility company or ODSA will terminate a customer's participation in PIPP Plus when it is determined that the PIPP Plus customer was fraudulently enrolled in the program. The customer will be required to pay the utility the actual bill for energy consumed during the period in which the customer was fraudulently enrolled. In addition, the customer will be prohibited from re-enrolling in PIPP Plus or Graduate PIPP Plus for twenty-four months. The arrearage credits which accrued to the customer's account will be reversed.

58. What happens if a PIPP Plus customer is charged with tampering?

The customer must pay the tampering charges which may include damages, investigation fees, and unauthorized usage prior to re-enrolling on PIPP Plus. The arrearage credits which accrued to the customer's account will be reversed.

59. What happens if a PIPP Plus customer writes a bad check?

The customer must pay the amount of the returned check, and the company's approved tariff returned check charge(s). Any arrearage credits applied to the customer's account will be reversed.

60. When two meters of the same type (i.e., two gas and/or two electric) are situated at one household/family dwelling, how should the utility company determine the PIPP Plus payment (e.g., a duplex unit that has been converted into a single family dwelling)?

The utility company should divide the customer's PIPP Plus installment between the two accounts.

61. What if the utility service is not in the PIPP Plus applicant's name?

If the service is not in the applicant's name, the applicant is ineligible for PIPP Plus. The applicant must first become a customer before he or she can go on PIPP Plus; however, the applicant can still apply for energy assistance for the household.

62. When a customer with an account balance moves out, how much must a consumer who lived with that person pay to obtain or to maintain service and get on PIPP Plus?

The consumer will be asked to provide proof that the customer has left the residence in order for the consumer to establish service in his/her name. The consumer is almost never responsible for the customer's bill if the household has changed. The consumer will need to apply for PIPP Plus at the HEAP Provider who will then determine if the consumer is income eligible.

63. What criteria are used to define income?

The household income is the gross income amount before taxes (minus exclusions) for all household members 18 years or older. Income earned by a dependent minor (less than 18 years old) in the household is excluded from the total household income calculation. Any questions regarding unusual situations should be brought to the attention of Office of Community Assistance at 1-800-282-0880. **(Please see Energy Assistance income guidelines in Appendix B.)**

64. Is a minor's income included in household income?

All wage or salary earned by a dependent minor (less than 18 years old) in the household is excluded from calculation. Only an emancipated minor may be considered a head of household. **(Please see Energy Assistance income guidelines in Appendix B.)**

65. How long does someone have to be at or below 150% of the federal income guidelines to qualify for PIPP Plus?

To be eligible for PIPP Plus, the total household eligible income for the last 30 days or 12 months from the date of the application must be equal to or less than 150% of the federal income guidelines. Seasonal and self-employed households must provide 12 months of income documentation.

- The lowest poverty level for either 30-day or 12 month period will be used to determine the benefit amount and threshold.

66. What if the customer disagrees with the PIPP Plus installment amount?

The PIPP Plus installment amount is calculated by the HEAP Agency or ODSA based on the income documentation provided by the customer. If a customer disagrees with the calculated amount of the PIPP Plus installment, the customer can contact ODSA or the local HEAP Agency to appeal. The customer may be required to provide additional documentation to support his/her dispute.

67. What information should be provided to verify income?

See Appendix B for Documentation and Calculation of Income

68. What if the household income is zero?

A customer whose household has no countable income is eligible for PIPP Plus. A zero-income customer must be able to explain why he/she is not on an entitlement program or, if the customer expects to receive benefits on such a program, when the benefits are due. The customer must be able to document how the household has existed. All applicants who claim zero income must apply for assistance in person at the local HEAP agency. **Mailed in applications will not be accepted.**

69. How often must zero-income PIPP Plus customers re-verify their income?

Customers who are zero-income must re-verify their household income no less than once every 12 months (within 60 days of the reverification date on the utility bill) or when there is a change in income/or household size or when requested to do so by the utility company. All applicants who claim zero income must apply for assistance in person at the local HEAP agency. **Mailed in applications will not be accepted.**

70. How much does a current PIPP Plus customer who is in default and is found to have zero income have to pay to enroll on zero-income PIPP Plus?

A customer who is currently on PIPP Plus and is reverified at zero income must cure any previous PIPP Plus default. When the customer's default is cured, the customer will then begin paying $10 per month minimum installment.

71. How should income be calculated when someone living in the unit pays rent to the customer?

Persons sharing a common kitchen and/or bath must be included as part of the household size and their income must be considered part of the household gross income.

72. Can Winter Crisis Program payments be applied as a PIPP Plus or Graduate PIPP Plus installment?

Yes, 2018-2019 Winter Crisis Program payments may be applied toward the current PIPP Plus/Graduate PIPP Plus default. To re-join PIPP Plus or Graduate PIPP Plus the customer must cure any remaining default over $175. **(See question 102).**

73. Can a Regular HEAP payment be applied as a PIPP Plus installment?

No. Regular HEAP payments may not be applied as monthly PIPP Plus payments. Energy assistance payments (winter, summer and Regular HEAP payments) will not be eligible for arrearage credits.

74. How are Energy Assistance payments applied?

- <u>Regular HEAP-</u> Payments are applied to the arrearages on the primary heating account, if any. If no arrearages are owed, the Regular HEAP payment will be applied as a credit balance on the primary heating account.

- <u>Winter Crisis-</u> Payments are applied toward the current PIPP Plus/Graduate PIPP Plus default balance. Winter Crisis payments can be applied toward both the primary or secondary heating source.

- Summer Crisis (Electric only) - Payments are applied toward the current PIPP Plus/Graduate PIPP Plus default balance. However, prior to receiving the credit/pledge the customer must pay the difference between the default and pledge amount.

- Utility Company Energy Assistance-Payments (i.e., Salvation Army, Neighbor to Neighbor, HEAT Share, and Fuel Funds) are applied toward the current PIPP Plus/Graduate PIPP Plus default balance. Any remaining credit is applied toward the arrearages.

75. What types of assistance must a customer apply for in order to go on PIPP Plus?

The customer must apply for and accept all ODSA energy assistance and weatherization programs for which he/she is eligible.

76. Does a customer have to apply for weatherization programs?

Yes, customers must apply for and accept assistance from all ODSA sponsored weatherization programs for which he/she is eligible.

77. Can a customer be removed from PIPP Plus if the customer refuses weatherization services?

Yes, the account can be removed from PIPP Plus if the customer refuses weatherization services offered by ODSA.

78. Does a HEAP Agency have to verify an applicant's income?

All electric and large gas PIPP Plus customers are reverified through the local HEAP Provider. Gas companies may not demand that a customer go to the HEAP Agency for verification unless they have established specific reverification procedures with ODSA. Some small gas companies may verify income at their local office for PIPP Plus.

79. Is the customer required to apply for non-energy assistance programs (i.e., Temporary Assistance for Needy Families (TANF)) to enroll on PIPP Plus?

No, the customer may be advised of these public assistance programs. However, customers **are required** to apply for all public energy and weatherization assistance.

REVERIFICATION DATE AND ANNIVERSARY DATE

80. What is the reverification date?

The reverification date is the actual date on which the customer completed documentation of household income. Reverification must occur no less than once every 12 months from the previous reverification date. A customer has a 60-day grace period to re-verify income before being removed from the program. The customer is required to re-verify whenever there is a change in household size and income. The customer's reverification date may change from year to year.

81. When must a customer re-verify the household income?

Any time there is a change in household income or size, the customer must re-verify his/her income. If there is no change in household income or size, customers are required to re-verify once every twelve months. The utility company may also request that the customer reverify his/her income. When a customer goes to the HEAP Provider to apply for energy assistance, his or her income will be reported to the company by the HEAP Agency or the ODSA.

82. How does a customer reverify his/her income for PIPP Plus?
A PIPP Plus customer must re-verify his/her income no later than the reverification date which is printed on the bill.

- Customers who need to reverify their household income and size can do so the following ways:
- Online at www.energyhelp.ohio.gov

- Download and complete an Energy Assistance application by going to www.development.ohio.gov

  Mail completed applications with documentation to:
  Ohio Development Services Agency
  P. O. Box 1240
  Columbus, OH 43216
- Mailed applications could take up to twelve weeks for processing.
- If applying by mail, customers must submit proof of income documentation as required by ODSA (See Appendix B for income documentation).
- Mailed applications will not be accepted for households claiming zero income. All applicants who claim zero income must apply for assistance in person at the local HEAP agency.
- For the mail-in application process, companies may also require that every adult member of the household sign a statement affirming that the information on the application is true and giving the company permission to verify the information provided.

83. What happens if a PIPP Plus customer does not re-verify his or her income on the reverification date?

A PIPP Plus customer must re-verify his/her income no later than the reverification date which is printed on the bill. A customer has a 60-day grace period to re-verify income before being removed from the program. A customer who does not re-verify his/her income when requested to do so, will be removed from PIPP Plus. The customer will be responsible for the total account balance if the account is removed from PIPP Plus.

84. What is a PIPP Plus anniversary date?

The PIPP Plus anniversary date is the date by which a PIPP Plus customer must make up any missed PIPP Plus installments in order to continue PIPP Plus. If the customer has missed payments in the past 12 months, the 1/24th arrearage credit will be recalculated at the anniversary date. (If the customer has made the past 12 installments on time the arrearage will not be recalculated).

85. What happens if the customer can not pay his/her missed installments by the anniversary date?

A customer who does not cure the missed installments at the anniversary date will be removed from PIPP Plus. Customers will have one billing cycle to make up the missed installments before being removed from PIPP Plus.

86. How will the customer be aware of his/her PIPP Plus anniversary date?

The anniversary date is shown on the customer's bill.

87. Is the customer required to go to the HEAP Provider at the anniversary date?

No, the customer is not required to return to the HEAP Provider at the anniversary date unless he/she is in default on PIPP Plus and is seeking energy assistance to cure the missed installments.

DISCONNECTION AND RECONNECTION

88. How much is a PIPP Plus customer required to pay if service is disconnected for non-payment?

A PIPP Plus customer must pay the amount sufficient to cure the PIPP Plus default (as stated on the disconnection notice) in order to reconnect service. The defaulted amount may include actual bill charges and PIPP Plus installments for those months the customer's service was disconnected, minus payments made, up to the customer's arrearage. The customer will also be charged a tariffed reconnect fee. (**See Special Reconnection Procedures Section**).

*During the winter heating season, PIPP Plus customers may utilize the winter reconnect order to have service restored for a maximum payment of $175, plus a tariffed reconnect fee (no more than $36 up front).

89. If a customer defaults on PIPP Plus, how much would he or she have to pay to avoid shut-off?

The customer can maintain service by paying the defaulted PIPP Plus installments as stated on the disconnection notice. During the winter heating season, PIPP Plus customers may utilize the Winter Reconnect Order to maintain service for a maximum payment of $175.00**. (See Special Reconnection Procedures).**

90. What does a customer have to pay to avoid disconnection when the total account balance is less than the PIPP Plus default?

To remain on PIPP Plus and avoid disconnection, the customer is required to pay the PIPP Plus default amount. If the customer no longer wants to be on PIPP Plus but wants to avoid disconnection, he/she can have the account removed from PIPP Plus and pay the total account balance or go on another payment plan with the utility company.

91. Is the PIPP Plus installment amount due shown on the bill or disconnection notice?

Yes, the PIPP Plus installment amount is shown on the bill. Also, the company must state on the disconnection notice the minimum amount required to avoid disconnection.

92. If a customer misses a PIPP Plus installment, is the company allowed to shut service off without further notice?

No, the company must give the required notice of disconnection prior to terminating service. The company may begin the notice process the day after the payment was due provided there is a 30-day account arrearage.

93. What is the earliest date a company may terminate service after the customer has defaulted on PIPP Plus?

During the ***non-heating season***, the earliest date a company may terminate service is the date stated on the 14-day disconnection notice unless payment or payment arrangements are made before this date.

During the ***heating season*** (Nov. 1 through April 15), the company must give a 14-day notice ***and*** an additional 10-day notice. The ten-day notice will extend the date of disconnection, as stated on the fourteen-day notice. Utility companies may send the 10-day notice by regular U.S. mail; however, the companies must allow three calendar days for mailing.

If the customer has selected both the electronic bill and notice option, the notices will be delivered electronically to the customer.

94. What are the reconnection requirements?

If the service has been disconnected for **10 business days or less**:

(1) The customer must provide proof of payment to the utility no later than 12:30 p.m. in order to guarantee reconnection of service the same day.

(2) If payment is not received by 12:30 p.m., the utility company will reconnect service by the close of the following regular utility company working day.

(3) Customers may request reconnection of service after normal business hours, **if the company offers such service**. The Company may require the customer to pay the approved tariff rate for this service prior to reconnection.

If the service has been disconnected for **more than 10 business days**, regardless of the time of day the customer payment is made:

(1) The company may treat the customer as a new customer.

(2) Gas service will be reconnected within **three** business days.

(3) Electric service will be reconnected within **three** business days.

(4) The utility company may assess a reconnection charge and a security deposit (Non-PIPP Plus account) to reestablish service.

PIPP PLUS RE-ENROLLMENT

95. Re-enrollment on PIPP Plus if service has been disconnected for non-payment

A PIPP Plus customer must pay the amount sufficient to cure the PIPP Plus default (as stated on the disconnection notice) in order to reconnect service. The defaulted PIPP Plus amount may include actual bill charges and PIPP Plus installments for those months the customer's service was disconnected, minus payments made, up to the customer's arrearage. Once the default amount is paid, the customer can re-enroll on PIPP Plus. The customer will also be charged a tariffed reconnect fee. (**See Special Reconnection Procedures Section**).

*During the winter heating season, PIPP Plus customers may utilize the winter reconnect order to have service restored for a maximum payment of $175, plus a tariffed reconnect fee (no more than $36 up front). However, to re-enroll on PIPP Plus/ Graduate PIPP Plus customers must pay the balance of the default on or before the due date of the next bill to re-enroll on PIPP Plus/Graduate PIPP Plus.

96. What must a former PIPP customer (enrolled prior to November 2010) pay to establish service and then enroll on PIPP Plus?

During the winter heating season, a customer who has never been enrolled on PIPP Plus and is income eligible for PIPP Plus can re-establish service by paying up to $175 or, his/her first PIPP Plus installment (whichever is less). Any remaining balance will be added to the arrearages and will be eligible for $1/24^{th}$ arrearage credits.

Customers who wish to enroll in PIPP Plus at any other time of the year will be required to pay the delinquent amount as stated on the final bill to re-establish service. After the service has been re-established the customer may enroll on PIPP Plus if eligible.

97. Re-enrollment on PIPP Plus if dropped for failure to re-verify (still has active service)

The customer must re-verify his/her household income. The customer must pay any defaulted PIPP Plus installments owed prior to being dropped and full bills for the months the customer received service but was not on PIPP Plus (less any payments made by the customer after being dropped). This includes PIPP Plus payments for any months in which the customer was disconnected. The amount owed shall not exceed the amount of the customer's arrearages.

98. Re-enrollment on PIPP Plus if dropped at the anniversary date (still has active service)

The customer must pay any defaulted PIPP Plus installments owed prior to being dropped and full bills for the months the customer received service but was not on PIPP Plus (less any payments made by the customer after being dropped). This includes PIPP Plus payments for any months in which the customer was disconnected. The amount owed shall not exceed the amount of the customer's arrearages.

99. Re-enrollment on PIPP Plus after being on Graduate PIPP Plus (active service)

If a customer who was on Graduate PIPP Plus becomes income eligible for PIPP Plus the customer must cure any Graduate PIPP Plus default amount prior to re-enrollment on PIPP Plus. During the winter months the customer can apply for the Winter Crisis Program (WCP) for assistance up to $175. The customer must cure any remaining default over $175 before the account can be re-enrolled on PIPP Plus.

100. Re-enrollment on PIPP Plus after receiving a refund of the credit balance

After receiving a refund of the credit balance, if the customer requests to re-enroll on PIPP Plus within a twelve-month period the customer must pay the difference between the amount of previous PIPP Plus installments and customer payments during those months the customer was not enrolled on PIPP Plus.

Note: Returning to PIPP Plus within a twelve-month period after receiving a refund of the credit balance could result in the customer having to pay more than the actual account balance.

101. Re-enrollment on PIPP Plus if default is higher than total account balance

If the PIPP Plus default is higher than the total account balance and the customer wants to re-enroll on PIPP Plus within a twelve-month period, the customer must pay the difference between the amount of PIPP Plus installments owed and customer payments during those months the customer was not enrolled in PIPP Plus.

Note: This could result in the customer having to pay more than the actual account balance to remain on PIPP Plus.

102. Re-enrollment on PIPP Plus or Graduate PIPP Plus after using the Winter Reconnect Order

To re-join PIPP Plus or Graduate PIPP Plus, the customer must cure any remaining default over $175 by the due date of the next bill issued. Once the default amount is paid, the customer can begin paying his/her PIPP Plus or Graduate PIPP Plus installment. *The time period (twelve months) is not extended to participate in Graduate PIPP Plus.*

The customer should contact the utility company to determine the exact amount of the remaining balance and the due date by which the bill needs to be paid to get the account re-enrolled on PIPP Plus/Graduate PIPP Plus.

103. Re-enrollment on PIPP Plus <u>within</u> twelve months after voluntary drop (customer request)

A PIPP Plus customer who voluntarily leaves **<u>with no outstanding arrearages</u>** and then **<u>within</u>** twelve months re-enrolls in PIPP Plus must pay the PIPP Plus payments due for the months the customer received service but was not on the program, less payment made by the customer during the same time period.
Note: This could result in the customer having to pay more than the actual account balance to remain on PIPP Plus.

A PIPP Plus customer who leaves **<u>with outstanding arrearages</u>** and then **<u>within</u>** twelve months re-enrolls in PIPP Plus must pay the PIPP Plus payments due for the months the customer received service but was not on the program, less payment made by the customer during the same time period.

104. Re-enrollment on PIPP Plus <u>after</u> twelve months after voluntary drop (customer request)

A PIPP Plus customer who leaves the program with **<u>no outstanding arrearages</u>** and then **<u>after</u>** twelve months re-enrolls in PIPP Plus would be required to pay his or her first PIPP Plus payment to re-join the program.

A PIPP Plus customer who leaves the program with **<u>outstanding arrearages</u>** and then **<u>after</u>** twelve months re-enrolls in PIPP Plus would be required to pay the missed PIPP Plus payments for the number of months that he/ she was not enrolled in PIPP Plus, less any payments made by the customer up to the amount of the arrearages.

MEDICAL CERTIFICATES

105. When can a medical certificate be used?

If a residential customer or consumer who is a permanent resident in the household is facing a situation where disconnection of service would be especially dangerous to his/her health, a medical certificate may used to maintain service or reconnect utility service within 21 days after the disconnection.

*PIPP Plus customers will not be eligible for any arrearage crediting for the months the customer uses the medical certificate unless on time and in full payments are made.

106. Who may request a medical certificate?

Upon request of any residential consumer, or a licensed physician, physician assistant, clinical nurse specialist, certified nurse practitioner, certified nurse mid-wife or local board of health physician the utility company must provide a medical certificate form. The medical certificate is available via the Public Utilities Commission of Ohio website (www.puco.ohio.gov).

107. How long does a utility company have to reconnect service after a medical certificate is presented to the utility company?

If certification is provided to the utility company prior to 3:30 p.m., the utility company must restore the customer's service the same day. If certification is received after 3:30 p.m., the company shall reconnect service by the earliest time possible on the following business day. If the certification is received after 3:30 p.m. on a day that precedes a non-business day, the utility company shall make an effort to restore service by the end of the day.

108. How often can a medical certificate be used?

The total certification period is not to exceed 90 days in any 12-month period. Medical certificates are valid for 30 days each, for a maximum of three times.

NOTE: If a medical certification is used to avoid disconnection, the customer must enter into an extended payment plan prior to the end of the medical certification period or be subject to disconnection. The initial payment on the plan shall not be due until the end of the certification period. ***PIPP Plus customers must make-up these missed installments at the Anniversary Date*** **(See question 84).**

109. Can a company disconnect service for non-payment if life-support equipment is in operation?

Yes, unless the customer uses a medical certificate.

110. Can a medical certificate be denied based on the customer's medical condition?

No, if a licensed physician, physician assistant, clinical nurse specialist, certified nurse practitioner, certified nurse mid-wife or local board of health physician signs the medical certificate.

111. Can a medical certificate be used for a cooking only account?

Yes, a medical certificate may be used for a cooking only account as long as the medical condition is certified by a licensed physician, physician assistant, clinical nurse specialist, certified nurse practitioner, certified nurse mid-wife or local board of health physician calls, writes or faxes the company and confirms to the company that the denial of service would be especially dangerous to the health of someone living in the household (within 21 days after the termination of service), the company *must* restore service or cancel the termination order.

MASTER METERED ACCOUNTS

112. What accounts are considered master metered?

An account is master metered if two or more residential premises share a common gas and/or electric meter.

113. Can a consumer who lives in a master metered residence enroll on PIPP Plus?

The consumer is not eligible for PIPP Plus for the main heating source if it is master-metered; however, the consumer ***may*** still be eligible for PIPP Plus for the secondary heating source.

114. Are master-metered accounts eligible for HEAP/Winter Crisis?

Yes, if the household is responsible for paying utility costs separately from his/her rent costs, he/she is eligible for an energy assistance benefit.

NOTE: Master-metered accounts are eligible for Weatherization Assistance.

115. Is the company required to issue a disconnect notice to the tenants of a master-metered premise?

Yes, the utility company must provide a 10-day notice to the tenants prior to disconnect. The company must make a good faith effort to provide this notice to each unit of a multi-unit dwelling and to post it in a conspicuous place.

116. What should the tenant do who has received such a notice or whose service has been disconnected?

A tenant who has received such a notice or whose service has been disconnected should immediately contact the utility company for further information or Ohio State Legal Services Association at 1-866-529-6446 for information about tenants' rights and landlord/tenant provisions.

SPECIAL RECONNECTION ORDER PROCEDURES FOR THE WINTER OF 2019-2020

117. What is the Winter Reconnect Order?

The Winter Reconnect Order (WRO) is issued by the PUCO. The WRO allows a customer to pay less than what he/she owes to avoid disconnection or reconnect service. A customer may pay a maximum of $175.00 to maintain service. If the customer's service has already been disconnected, the customer must pay the $175.00 and a tariffed reconnection fee of no more than $36 up front to restore service. The company will bill the remainder of the reconnect fee, if applicable.

118. Who offers the Winter Reconnect Order?

All regulated electric and gas companies must offer the Winter Reconnect Order.

119. Who is eligible to use the Winter Reconnect Order?

There is no income eligibility requirement to use the Winter Reconnect Order. Any residential customer who is served by a regulated utility company may use the Winter Reconnect Order to maintain or restore his/her service **one time** during the winter heating period.

120. When can the Winter Reconnect Order be used?

The Winter Reconnect Order may be used **once** from Monday, October 14, 2019 through Wednesday, April 15, 2020 (close of business).

121. How much is a customer required to pay with the Winter Reconnect Order?

Customers are required to pay no more than $175 to maintain service under the reconnection order. If the customer's service has already been disconnected, the customer must pay the $175 and a tariffed reconnection fee of no more than $36 up front to restore service.

NOTE: If paying at an authorized agent, the customer will need to call the company with the receipt number to report the payment. Some companies may require that the customer notify them that the Winter Reconnect Order is being used.

122. How does a customer sign up for the Winter Reconnect Order?

There is no sign up required. The Winter Reconnect Order is not based on any income requirements. Anyone, (regardless of income) can use the Winter Reconnect Order if service has been disconnected or is being threatened with disconnection.

123. What if a customer owes more than $175 to the utility company?

Customers who use the Winter Reconnect Order are required to enroll on a payment plan for the remaining balance. Regulated gas and electric companies are required to offer the following payment plans:

- **One-Sixth Payment Plan (offered year-round)**-A plan that requires either six equal monthly payments on the arrearages in addition to full payment of current bills; **or**

- **One-Ninth Payment Plan (offered year-round)**-A plan that requires nine equal monthly payments on the arrearages in addition to a budget payment plan (established by the utility company); **or**

- **One-Third Payment Plan (offered from November 1 through April 15)**-A plan that requires payment of one-third of the balance due each month (arrearages plus current bill).

- **PIPP Plus/Graduate PIPP Plus** customers must pay the balance of the default on or before the due date of the next bill to re-enroll on PIPP Plus/Graduate PIPP Plus.

NOTE: The customer or the HEAP Agency must contact the utility company to enroll the customer in a payment plan other than PIPP Plus.

124. When does the remaining PIPP Plus default have to be paid after the $175 payment/pledge?

The remaining balance of the PIPP Plus default must be paid by the due date of the next bill that is issued.

125. Can the $175 payment be split between the gas and electric utility companies?

Yes. If the customer is served by two regulated utility companies (gas and electric) and is facing disconnection or service has been disconnected the utility companies involved may split the $175 (either by apportionment based on the arrearages or in half). For customers who are eligible for the Winter Crisis program the split will be calculated by the HEAP agency.

126. Can the $175 payment be split between the gas and electric utility companies to begin new service?

Yes, if the customer is served by two regulated utility companies the WRO can be split in order to establish new service with both companies.

127. When is the Winter Reconnect Order applied?

The Winter Reconnect Order allows customers to pay less than what they owe to maintain service or reconnect service. Therefore, the WRO is invoked only when customers pay less than the amount owed to prevent a disconnection or reconnect their service.

Example: If a customer receives a disconnection notice in the amount of $150 and the customer receives assistance through an agency for $150, the WRO should **not** be applied because the agency payment covered the amount needed to avoid disconnection. The customer could invoke the WRO using his/her own funds at a later time.

128. Will the $175 payment maintain service?

Yes, the $175 payment/pledge will maintain service for a minimum of thirty days. Non-PIPP Plus customers are required to enroll on an extended payment plan for the remaining balance. PIPP Plus/ Graduate PIPP Plus customers must pay the balance of the default on or before the due date of the next bill to re-enroll on PIPP Plus/Graduate PIPP Plus. **(See question 123 for payment plan options).**

129. Will the $175 payment reconnect utility service?

Yes, the customer may be required to pay a tariffed reconnection charge of no more than $36 up front to restore service. The remaining amount of the reconnection fee will be billed on the next bill issued.

130. What is a tariffed reconnection charge?

A tariffed charge is one which has been approved by and is on file with the Public Utilities Commission of Ohio (PUCO). The Winter Reconnect Order procedures do not allow companies to charge more than they otherwise are allowed in their tariff as a reconnection charge. Any company that doesn't have a tariffed reconnection charge may not assess one.

131. What if the company's tariffed reconnection charge is more than $36, what happens to the difference between the $36 paid and the tariffed amount?

The company can bill the difference between the $36 and the tariffed reconnection charge on the customer's next monthly bill or the company may bill the entire tariffed reconnect fee on the customer's next monthly bill.

132. Can the $175 payment be made by an agency?

Yes, the $175 may be paid by any agency providing energy assistance (i.e., Salvation Army, HEAT Share, Neighbor to Neighbor, Fuel Funds, etc.).

133. Can the utility company disconnect service if the customer has a pending appointment with a HEAP Provider for the Winter Crisis Program?

No, the utility company will delay disconnection if the customer has a confirmed appointment with a local HEAP Agency for the winter crisis program and the customer has not already utilized the WRO with their own funds. The utility company will delay the disconnection until five business days after a customer's confirmed appointment.

The utility company is only required to hold a disconnection for an appointment **once** per heating season.

134. Can the utility company require a security deposit before reconnecting service?

Yes, customers who are not eligible for PIPP Plus may be assessed a security deposit. However, the total amount the company may require a customer to pay, including the security deposit, may not exceed the Winter Reconnect Order ($175) amount for reconnection.

135. Can the Winter Reconnect Order be used in lieu of paying a security deposit?

Yes, in lieu of paying the required security deposit customers who are requesting new service with no previous balance may establish new service upon payment of $175. The company may add the remaining balance of the required security deposit to the customer's next bill. ***NOTE: Customers who are enrolled in PIPP Plus will not be charged a security deposit.***

136. Can a customer transfer service using the Winter Reconnect Order?

Yes, a customer who requests service at a new address and has an outstanding balance greater than $175 can transfer service upon payment of $175. The customer **must** contact the company and enter into a payment arrangement on the remaining balance. If a PIPP Plus/Graduate PIPP Plus customer has reverified his/her income within the last 12 months, the company shall transfer service upon payment of $175.

137. What happens if a customer uses the Winter Reconnect Order using his/her own money and later goes to an agency for assistance?

If a customer pays the $175 with his/her own funds and later (during the winter) goes to an agency for assistance, the customer **must** immediately pay the difference between the default amount and the $175 that the agency is willing to pledge to avoid disconnection.

138. Is the utility company required to reconnect service the same day under the Winter Reconnect Order?

See question 94 for reconnection procedures.

139. Can a customer with multiple residential accounts use the Winter Reconnect Order?

Customers with multiple residential accounts who wish to utilize the winter reconnection order to maintain or reconnect service may do so only at the property where the customer resides.

140. Can a customer who is with a supplier (CRNGS or CRES) use the Winter Reconnect Order?

Yes, customers who have a supplier may use the Winter Reconnect Order to stop a disconnection or reconnect their utility service. All provisions of the winter reconnect order would apply to customers that have a supplier.

APPENDIX A

ENERGY ASSISTANCE PROGRAMS OVERVIEW

Home Energy Assistance Program (HEAP) (also called 'Regular HEAP' or State HEAP) – is a federally funded program designed to help income-eligible Ohioans with their winter heating bills. The program runs from November 1 through March 31. Eligible customers receive a benefit in the form of a direct payment toward their energy heating bill. HEAP benefits are typically credited directly towards the eligible customer's energy heating bill beginning in the month of January. Applications that are mailed into the Office of Community Assistance (OCA) may take 12 to 16 weeks for processing. Applications may also be processed at the local HEAP Agency.

The total household income of an applicant must be at or below 175% of the federal income guidelines. **See income guidelines question 3**.

Winter Crisis Program (WCP) (also called 'Emergency HEAP' or E-HEAP) – provides financial assistance to income-eligible households that are threatened with disconnection of their heating source; have already had service disconnected; need to establish new service or pay to transfer service; or in the case of bulk fuel customers, have 25 percent or less of the tank's fuel capacity on hand. The WCP program year runs from November 1 to March 31. Agencies have until April 15 to finish processing incomplete or pending applications for the current year's program.

Households whose gross income is at or below 175% of the federal income guidelines are eligible for the Emergency Program. **See income guidelines question 3**.

Summer Crisis Program (SCP) (also called 'Summer Cooling) - provides financial assistance to income-eligible Ohioans to help with their summer cooling costs. Income-eligible individuals age 60 or older or with a certified medical condition are eligible. The SCP program year runs from July 1 to August 31. Agencies have until September 15 to finish processing any incomplete or pending applications for the current year's program.

Percentage of Income Payment Plan (PIPP) Plus – helps income-eligible Ohioans manage their energy bills year-round. The program allows eligible Ohioans to pay their energy bill based on a percentage of their monthly household income. To be eligible for the program, a customer must receive his/her electric or gas service from a company regulated by the Public Utilities Commission of Ohio (PUCO), must have a total household income which is at or below 150 percent of the federal income level, and must apply for all ODSA energy assistance programs for which he or she is eligible.

Home Weatherization Assistance Program (HWAP) - Ohio's Home Weatherization Assistance Program (HWAP) is a federally funded low-income residential energy efficiency program. The HWAP program reduces low-income households' energy use, thus creating more affordable housing for those in most need. HWAP services may include attic, wall, and basement insulation; blower door guided air leakage reduction; heating system repairs or replacements; and health and safety testing and inspections. All measures are provided based on an on-site energy audit and cost-effective guidelines developed using the National Energy Audit Tool (NEAT) energy audit software program. Individualized client education is an important component of the HWAP program.

Households at or below 150% of the federal income guidelines or households participating in Home Energy Assistance Program, Temporary Assistance for Needy Families, or Supplemental Security Income qualify for this no cost program.

Electric Partnership Program (EPP) - is a no-cost program designed to improve the electric energy efficiency of households who participate in, or who are eligible for, PIPP Plus. The goal of EPP is to reduce the customer's electric usage by installing energy efficient items and creating a customized action plan. The program provides: A snapshot of how electricity is used in the client's home, an energy consumption analysis of all refrigeration appliances, suggested actions that the consumer can take to reduce electric usage without sacrificing comfort, installation of cost-effective energy efficient items and a report of the projected energy and dollar savings for the installed measures and actions. To be eligible the customer must have a regulated electric utility, be a PIPP Plus participant or PIPP Plus eligible, have a minimum annual electric baseload usage of 5,000 kWh and have lived at the residence for one year.

APPENDIX B
Documentation and Calculation of Income

Countable Income Types:		
Category:	**Type:**	**Acceptable Documentation of Income:**
Fixed Countable Income	☐ Supplemental Security Income (SSI) ☐ Social Security Disability Insurance (SSDI) ☐ Social Security Administration (SSA) ☐ Pension ☐ Widow/Widower's benefit ☐ Alimony ☐ Black Lung Pension	☐ Award/Benefit Letter ☐ Payment Printout/statement from issuing agency ☐ Copy of Check or Bank Statement showing deposit ☐ Most recent IRS Form 1099 ☐ Most recent filed copy of IRS Form or Tax transcript
Earned Countable Income	☐ Wages	☐ All pay stubs received 30 days from the date of the application that include gross and year-to-date amounts received ☐ Completed and signed Employment Verification Form (Appendix VI)
	☐ Active Military Pay	☐ Check Stub/Pay Statement
Other Earned Countable Income	☐ Seasonal Employment (includes construction workers, teachers, landscapers, etc.)	☐ Pay stubs indicating amount received within the previous 12 months from the date of the application ☐ Seasonal income will be determined by dividing the 12-month amount by 12 to arrive at a monthly average (Appendix VII)
	☐ Self-employment (includes owning own business, babysitting, home party sales, odd jobs, Ohio Electronic Child Care etc.)	☐ Most recent filed copy of IRS Form 1040 and Schedule 1 using the amount listed on line 12, 17, and/or 18 ☐ Most recent IRS Form 1099 Misc. ☐ Most recent IRS Record of Account Transcript ☐ Self-Employment Income Form (Appendix V) for the previous 12 months and
Supplemental Countable Income	☐ Unemployment	☐ Copy of check ☐ ODJFS documents/Eligibility letter with amounts and dates ☐ Most recent IRS Form 1099
	☐ Utility Assistance	☐ Housing Authority Documentation, ☐ Lease/Rental Agreement
	☐ Workers' Compensation	☐ Award letter issuing agency (BWC) ☐ Copy of check or bank statement
	☐ Ohio Works First (Temporary Assistance for Needy Families (TANF). Aid to Dependent Children (ADC))	☐ Award/Benefit Letter, or ☐ Payment Printout/statement from issuing agency, or ☐ Copy of Check or Bank Statement showing deposit

Countable Income Types Continued:		
Category:	**Type:**	**Acceptable Documentation of Income:**
Other Countable Income	☐ Cash withdraws from: IRA, Annuities, Other investments ☐ Lump sum payout from: SSI, SSDI; Estate & Trust settlements, Divorce settlements, insurance payout, lottery winnings ☐ Interest Income ☐ Other	☐ Statement from Financial Institution ☐ Copy of Check or Bank Statement showing deposit ☐ Most Recent IRS Form 1099 ☐ Calculate lump sums received by dividing the total amount by 12 months
No Income		☐ Self-Declaration of Income Worksheet (Appendix IV) ☐ An IRS tax transcript or an IRS Verification of Non-Filing Letter may be provided by the customer at the discretion of the LDA

Deductions:		
Category:	**Type:**	**Acceptable Documentation of Income:**
Deductions	☐ Health Insurance Premiums (Dental and Vision Insurance) ☐ Short-and Long-Term Disability Premiums (AFLAC, supplemental, etc). ☐ Prescription plans ☐ Health Care Spending Accounts ☐ Medicaid Spend Down (deductibles) ☐ Medicare Part B ☐ Medicare Part D (RX premium)	☐ Copy of Premium Statement showing payment ☐ Proof of Payment i.e. cancelled check or paystub
	☐ Child Support paid-out	☐ Proof of Payment i.e. cancelled check or paystub identifying garnishment
	☐ Attorney fees for estate or trust settlements	☐ Proof of Payment i.e. cancelled check
	☐ Self-employment IRS allowable business expenses	☐ Most recent filed copy of IRS Form 1040 ☐ Self-Employment Income and Expense Form and IRS Verification of Non-Filing Letter (if applicable
	☐ Reimbursement for work expenses (i.e. travel, mileage, meals, etc.)	☐ Pay Statement

Excluded Income:		
Category:	**Type:**	**Acceptable Documentation of Income:**
Excluded Income* *Only documented if the household's total Eligible Income (Countable Income – Deductions) is below the required threshold.	☐ Gifts	☐ Signed statement from provider of gift indicating amount and frequency, provider name, address and phone number
	☐ Loans ☐ Education assistance (grants stipends for tuition/books)	☐ Official notification of loan on institution letterhead including loan amount and repayment terms from issuing financial institution ☐ Signed statement from lender indicating amount and payment terms, lender's name, address and phone number ☐ School documentation demonstrating education assistance amount
	☐ Child Support Received ☐ Stipends for foster care ☐ Adoption Assistance	☐ Award/Benefit Letter, or Payment Printout/statement from issuing agency, Pay Statement or copy of canceled check or bank statement
	☐ Agent Orange Pension	☐ Payment Printout/statement from issuing agency
	☐ Service Connected Veterans Disability, VA Compensation/Dependent Indemnity Compensation (DIC)	☐ Statement from Issuing Agency ☐ Award Letter with Benefit Amounts ☐ Bank Statement (if income type is specified) ☐ Special Monthly Compensation (SMC), Person Care Services/Caregiver Stipend Program
	☐ Work programs for people with disabilities (i.e., work programs for the blind or disabled) ☐ Transportation allowances (WIOA) ☐ Volunteers in Service to America Stipend (VISTA) ☐ Work allowances (work requirement to receive OWF assistance) ☐ Title V wages (i.e. senior employment programs) ☐ Ohio waiver program (Medicaid benefit for caregiver)	☐ Award/Benefit Letter, or Payment Printout/statement from issuing agency, Pay Statement

Excluded Income Continued:		
Category:	**Type:**	**Acceptable Documentation of Income:**
Excluded Income	☐ Income earned by dependent minors	☐ All pay stubs received 30 days from the date of the application that include gross and year-to-date amounts received ☐ Completed and signed Employment Verification Form (Appendix VI)
	☐ Tax refunds/rebates	☐ Most recent IRS Form
	☐ Military allowances for subsistence	☐ Award/Benefit Letter, or Payment Printout/statement from issuing agency
	☐ Prevention retention and contingency (i.e. emergency services, rental asst.) ☐ FEMA, cash payments ☐ Title III Disaster relief emergency assistance	☐ Award/Benefit Letter, or Payment Printout/statement from issuing agency
	☐ Proceeds from reverse mortgage	☐ Payment Printout/statement from issuing agency
	☐ Fair market value of service in lieu of rent	☐ Signed statement from the Landlord ☐ Lease/Rental Agreement

APPENDIX C
SMALL GAS COMPANIES PIPP

	Grandfathered PIPP (10% of monthly household income)	PIPP Plus 6% monthly household income	Will accept new Enrollees	Re-enroll on Grandfathered PIPP	Alternative Arrearage Credit Program
Arlington Natural Gas	Yes	No	No	No	No
Brainard Gas Company	Yes	No	No	No	No
Eastern Natural Gas	No	Yes	Yes	No	Yes
Glenwood Energy of Oxford*	No	Yes	Yes	No	Yes
Northeast Ohio Natural Company	No	Yes	Yes	No	Yes
Ohio Cumberland Gas	Yes	No	No	No	No
Ohio Gas Company	No	Yes	Yes	No	Yes
Ohio Valley Gas**	No	Yes	Yes	Yes	Yes
Orwell Natural Gas Company	Yes	No	No	No	No
Piedmont Gas Company	Yes	No	No	No	No
Pike Natural Gas	No	Yes	Yes	No	Yes
Sheldon Gas Company	Yes	No	No	No	No
Southeastern Natural Gas	No	Yes	Yes	No	Yes
Waterville Gas and Oil Company	Yes	No	No	No	No

APPENDIX D
DEFINITION OF TERMS

Anniversary Date – The calendar date by which the PIPP Plus customer must be current on his/her installment payments to remain on the PIPP Plus program for the next year. The customer will have one billing cycle to make up any missed installment payments to remain on the program. Additionally, the customer's 1/24th credit will be recalculated at this time. The amount will not change if the customer has made on-time and in-full payments the previous 12 months. This date will be on the monthly utility bill.

Reverification Date- The actual date on which the customer completed documentation of household income. Reverification must occur no more than 12 months from the previous reverification date. Since the customer is required to re-verify any change in household size and income, the customer's reverification date may change from year to year.

PIPP Plus Annual Verification Date – The calendar date at or about 12 months from the customer's most recent reverification date.

PIPP Plus Default - The amount the customer owes in missed monthly PIPP Plus installments. (E.g., customer's PIPP amount is $50.00 per month and the customer has not paid for two months, the PIPP default is $100.00).

Graduate PIPP Plus Default - The amount the customer owes in missed monthly Graduate PIPP Plus installments. (E.g., customer's Graduate PIPP amount is $72.00 per month and the customer has not paid for two months, the Graduate PIPP default is $144.00). **The time period is not extended to participate in the Graduate PIPP Plus.**

PIPP Plus Arrears - The customer's arrearage as of the customer's PIPP Plus enrollment date. This amount will increase or decrease depending on the customer's future on-time payments. The customer is not obligated for the amount as long as he/she remains current on PIPP Plus. (E.g., customer owes the company $850.00, prior to going on PIPP Plus, the customer makes his/her first PIPP Plus payment of $50.00 the remaining $800.00 is the PIPP Plus arrears).

Total Account Balance - The full amount of the customer's bill, which includes all charges that the customer currently owes the company. If the customer remains current on PIPP Plus, at no time shall the total account balance become due. If the customer becomes ineligible for PIPP, due to a change in income or household size, he/she would then be eligible for the Graduate PIPP Plus program.

Total Balance Due - Utility companies may use this term interchangeably, as the total account balance or the total balance due to keep service on. (E.g., a customer's total balance could be $5,000; however, the total balance due to keep service on could be $200).

These definitions are to be used as a guide to help you understand the terms that are used interchangeably by utility companies when discussing account information. In all cases, please ask the company representative to explain the term that is being used to discuss the customer's account.

APPENDIX E
ELECTRIC COMPANIES RECONNECTION CHARGES
(Subject to Change Upon Commission Approval)

AEP Ohio	$ 53.00	
	$ 154.00	at pole
Cleveland Electric Illuminating	$ 35.00	at meter
	$ 60.00	same day after 12:30 p.m.
Dayton Power & Light (Electric)	$ 25.00	at meter
	$ 84.00	at service line
Duke Energy Ohio	$ 10.00	Remote meter
	$ 27.00	both electric and gas
Ohio Edison	$ 35.00	
	$ 60.00	same day after 12:30 p.m.
Toledo Edison	$ 35.00	
	$ 60.00	same day after 12:30 p.m.

APPENDIX F
GAS COMPANIES RECONNECTION CHARGES
(Subject to Change Upon Commission Approval)

Arlington Gas	$ 21.00	
Brainard Gas	$ 25.00	
	$ 37.50	after hours
Columbia Gas	$ 52.00	
Dominion East Ohio Gas	$ 33.00	
Duke Energy Ohio	$ 17.00	due payment problems
	$ 27.00	both gas and electric
Eastern Natural Gas	$ 30.00	
	$ 35.00	after hours
Foraker Gas Company	$ 25.00	
Glenwood Energy of Oxford	$ 50.00	
Northeast Ohio Natural Gas	$ 35.00	
Ohio Cumberland Gas	$ 30.00	
Ohio Gas Company	$ 40.00	
Ohio Valley Gas	$ 80.00	
Orwell Natural Gas	$ 30.00	
Piedmont Gas Company	$ 50.00	
Pike Natural Gas	$ 30.00	
Sheldon Gas Co.	$ 25.00	

APPENDIX F
GAS COMPANIES RECONNECTION CHARGES
(Subject to Change Upon Commission Approval)

Suburban Natural Gas	$ 20.00
Swickard Gas Co.	$ 30.00
Vectren	$ 60.00
Waterville Gas & Oil	$ 50.00

The Public Utilities Commission of Ohio

180 E. Broad Street
Columbus, Ohio 43215
(800) 686-PUCO (7826)

EXHIBIT JH-4

2014 STATE-BY-STATE RATEPAYER FUNDED LOW-INCOME ENERGY ASSISTANCE AND ENERGY EFFICIENCY			
State	Rate Assistance	Energy Efficiency	Total
Alabama	$1,733,283	$0	$1,733,283
Arizona	$51,514,973	$4,394,227	$55,909,200
Arkansas	$0	$275,564	$275,564
California	$1,403,200,000	$390,700,000	$1,793,900,000
Colorado	$10,675,168	$7,455,567	$18,130,735
Connecticut	$26,357,482	$29,396,267	$55,753,749
Delaware	$400,000	$400,000	$800,000
District of Columbia	$9,870,524	$6,099,890	$15,970,414
Georgia	$23,489,716	$2,750,000	$26,239,716
Idaho	$0	$2,255,097	$2,255,097
Illinois	$64,100,000	$11,668,214	$75,768,214
Indiana	$7,264,720	$6,996,341	$14,261,061
Iowa	$0	$6,210,739	$6,210,739
Kentucky	$2,982,799	$0	2,982,788
Maine	$8,121,857	$3,273,335	$11,395,192
Maryland	$62,300,000	$34,976,592	$97,276,592
Massachusetts	$123,969,642	$38,545,744	$162,515,386
Michigan	$50,000,000	$30,626,383	$80,626,383
Minnesota	$18,459,657	$8,190,253	$26,649,910
Mississippi	$850,000	$752,951	$1,602,951
Missouri	$0	$2,897,877	$2,897,877
Montana	$5,105,824	$3,090,679	$8,196,503
Nevada	$5,667,477	$3,076,218	$8,743,695
New Hampshire	$15,220,892	$5,016,103	$20,236,995
New Mexico	$0	$846,325	$846,325
New Jersey	$234,339,731	$31,700,000	$266,039,731
New York	$120,400,000	$59,325,256	$179,725,256
North Dakota	$0	$13,200	$13,200
Ohio	$334,638,817	$65,909,369	$400,548,186
Oklahoma	$12,000,000	$9,084,760	$21,084,760
Oregon	$21,063,985	$11,724,663	$32,788,648
Pennsylvania	$360,846,482	$48,619,871	$409,466,353
Rhode Island	$9,873,150	$21,192,491	$31,065,641
Texas	$392,409,318	$25,592,915	$418,002,233
Utah	$5,375,671	$1,040,345	$6,416,016
Vermont	$2,171,836	$932,679	$3,104,515
Washington	$44,558,252	$6,592,174	$51,150,426
West Virginia	$0	$1,485,264	$1,485,264
Wisconsin	$43,200,000	$36,836,700	$80,036,700
Total	$3,472,161,245	$919,944,053	$4,392,105,298
Source: https://liheapch.acf.hhs.gov/Supplements/2014/supplement14.htm			
Notes: Energy Efficiency totals for Missouri, New Mexico, North Dakota and West Virgnia are from NASCSP's Weatherization Assistance Program Funding Survey PY 2014. Mississippi and Oklahoma rate assistance are estimates for 2014.			

EXHIBIT JH-5

I/A

EVALUATION OF DUKE ENERGY'S HELPING HOME FUND

October 15, 2017

advanced energy

DUKE ENERGY®

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N.C. Community Action Association

LOCKHEED MARTIN

EXECUTIVE SUMMARY

Between 2015 and 2017, Duke Energy worked with the North Carolina Community Action Association (NCCAA) and Lockheed Martin to administer the Helping Home Fund, a program helping low-income customers improve their health and safety and manage their energy costs.

Duke Energy was the funding sponsor, with Duke Energy Carolinas and Duke Energy Progress providing a total of $20 million to support appliance replacement, health and safety measures, weatherization, and heating/cooling replacement and repair in participating homes. NCCAA was chosen as the program administrator and contracted with Lockheed Martin to assist with implementation.

In all, the Helping Home Fund reached 3,516 homes with an average of $5,151 in performed work per home. The Helping Home Fund was designed to leverage additional funding as well, including the State Weatherization Assistance Program (NCWAP), which consists of U.S. Department of Energy (DOE) Weatherization Assistance Program (WAP) and Low Income Home Energy Assistance Program (LIHEAP) funds, the PNC Home Beautification Fund, and funds from the North Carolina Housing Finance Agency (NCHFA). Without the Helping Home Fund, more than 40 percent of the participating homes would have been deferred due to funding limitations and program guidelines in the NCWAP. During the time period that the Helping Home Fund was operating, the program spent $20 million. Leveraged funding included:

- **NCWAP: $17 million**
- **PNC Home Beautification: $250,000**
- **NCHFA: $234,000**

Funds were also leveraged from other private funding sources, such as the City of Raleigh and City of Charlotte Urgent Repair Programs, but we were unable to obtain data on their funding levels.

Duke Energy had an interest in understanding the full impact of the program, including leveraging opportunities, and economic and non-energy impacts, such as health, safety and comfort. A number of approaches were taken for this effort. First, the team developed two surveys that were distributed to participating homeowners and service providers. The surveys gauged views of the Helping Home Fund and how people thought the program impacted the lives of families and the larger community. Second, a review of prior research evaluated the monetized values of potential energy and non-energy benefits associated with the program.

Results from the surveys demonstrated that both homeowners and service providers had a very favorable view of the Helping Home Fund. Homeowners noted that they felt safer, more comfortable and healthier in their homes, and reported financial savings that would allow them to pay for other necessities. Service providers applauded the program for its flexibility, staff and communication. Furthermore, the literature review of other low-income weatherization programs revealed that homeowners experienced a variety of non-energy benefits. Conservative estimates in the literature found monetized values for these benefits to be between $4,500 and $10,000 per home.

With the success of the program and the merger between Duke Energy and Piedmont Natural Gas, an additional $2.5 million will be used for a similar program to provide assistance to even more income-qualified families in North Carolina.

The Helping Home Fund reached 3,516 homes with an average of $5,151 in performed work per home.

INTRODUCTION

As a result of the Duke Energy North Carolina rate cases in 2013, Duke Energy allocated $20 million ($10 million from Duke Energy Carolinas [DEC] and $10 million from Duke Energy Progress [DEP]) to assist low-income customers. For both utilities, the $10 million was allocated in the following ways: $3 million was used for health and safety measures and appliance replacement (for DEP, some of these funds also went toward weatherization; DEC has a separate weatherization program), and $7 million was used for heating/cooling system replacement and repair. The actual breakdown of the funds at the time of this report can be seen in **Table 1**.

The program provided income-qualified customers with repairs and energy efficiency upgrades at no cost.

This program, known as the Helping Home Fund, ran from January 2015 to May 2017. The goal of the funding was to assist low-income customers. Duke Energy saw an opportunity to provide assistance that did not currently exist by providing health and safety repairs, new energy-efficient appliances, and heating systems to help homeowners manage energy costs and increase their disposable income. To meet this goal, the Helping Home Fund worked primarily through weatherization service providers as well as other non-profit agencies that serve families at or below 200 percent of federal poverty guidelines. The program provided income-qualified customers with repairs and energy efficiency upgrades at no cost.

The Helping Home Fund was funded by Duke Energy and administered by the North Carolina Community Action Association (NCCAA). NCCAA partnered with Lockheed Martin, who provided the database for data tracking and reporting, and quality assurance (QA) and quality control (QC). The Helping Home Fund was designed to leverage the State Weatherization Assistance Program (NCWAP) and other public/private funding sources. The funds were allocated to local North Carolina weatherization service providers and several non-profit agencies who completed the projects and were reimbursed once the work was completed. The program was allowed to use 10 percent of the funding for administrative purposes, with 5 percent going to the administrator and 5 percent to the service providers.

The monies were transmitted in total to the NCCAA to manage and deposited at PNC Bank. As a result, PNC Bank suggested that the NCCAA apply for a grant from their foundation, which ultimately provided another $250,000 for Helping Home Fund recipients for external beautification or maintenance, such as painting, roof repairs or landscaping.

TABLE 1 • HELPING HOME FUND BREAKDOWN

	DEC	DEP	TOTAL
APPLIANCE REPLACEMENT	$950,343	$620,399	$1,570,742
HEALTH & SAFETY	$1,765,387	$873,998	$2,639,385
HEATING/COOLING REPLACEMENT/REPAIR	$6,395,779	$6,388,239	$12,784,018
WEATHERIZATION TIER 1		$100,217	$100,217
WEATHERIZATION TIER 2		$1,018,932	$1,018,932
PROJECT TOTAL	**$9,111,509**	**$9,001,785**	**$18,113,294**
AVERAGE PER HOUSE			$5,151
ADMINISTRATION	$928,344	$928,344	$1,856,688
OVERALL TOTAL	**$10,039,853**	**$9,930,129**	**$19,969,982**

INTRODUCTION

Because of federal regulations, the NCWAP has a limited amount of funding it can use per house for health, safety and energy measures. If repair monies were not available from either federal or local sources, the home would be deferred. The Helping Home Fund filled this gap, allowing the NCWAP to serve customers who would have otherwise been deferred by service providers by providing the funding to make the needed repairs. Furthermore, North Carolina weatherization agencies' energy efficiency improvements waitlist had been experiencing lengthy delays, and customers were not getting work scheduled or completed. The funding provided additional services to customers and helped to leverage federal and state funds for maximum customer benefit and impact.

The Helping Home Fund focused on four main components:

- 01 Health and safety
- 02 Appliance replacement
- 03 Weatherization (in DEP territory only)
- 04 Heating/cooling system replacement and repair

In DEC territory, homes already had access to weatherization through the existing energy efficiency Weatherization Program.

LM Captures is Lockheed Martin's tracking and reporting system that service providers used to enter the individual home data for the program. The database required comprehensive data input for customer, home and project details to determine eligibility and track program expenditures and measure level detail by project type. All program activities, including QA/QC and reimbursement request/fulfillment, were also reported.

Funds for health and safety were originally capped at $800 per home, but due to customer needs learned throughout the program, the limit was later raised to $3,000. Health and safety measures included bath fans, vapor barriers, roof repairs, electrical/plumbing repairs, ingress/egress repairs, range repair and replacement, and water heater repair and replacement. Appliance replacement also started with an allotment of $800 per home, but this amount was increased to $2,000. This work included replacing inefficient appliances with ENERGY STAR® refrigerators, clothes washers, clothes dryers and room air conditioners.

Weatherization services were broken down into two tiers.

TIER 1

Tier 1 weatherization was for homes using < 7 kilowatt-hours (kWh) per square foot, < $0.23 per square foot oil/liquid propane (LP) gas heat, or < $0.38 per square foot oil/LP gas heat and water heating. Up to $600 was allotted for the following measures:

- Heating system tune-up and cleaning
- Heating system repair
- Water heater wrap and pipe wrap for electric water heaters
- Cleaning or replacement of electric dryer vents
- ENERGY STAR-certified compact fluorescent lamps (CFLs)
- Low-flow showerheads and aerators
- Weatherstripping doors and windows
- Energy education

INTRODUCTION

TIER 2

Tier 2 weatherization was provided to homes using ≥ 7 kWh per square foot, ≥ $0.23 per square foot oil/LP gas heat, or ≥ $0.38 per square foot oil/LP gas heat and water heating. Here, up to $4,000 was provided for the following:

- **Tier 1 services**
- **Attic insulation**
- **Air sealing**
- **Duct sealing/repair**
- **Wall insulation**
- **Crawl space insulation**
- **Floor insulation**

Since heating/cooling systems account for the majority of an energy bill, 70 percent of the monies were allocated to improve customers' heating systems. The intent was to decrease customers' energy use, thereby providing them with more disposable income. Existing electric furnaces, electric baseboards, and oil or propane systems were replaced with high efficiency heat pumps (minimum 14 Seasonal Energy Efficiency Ratio [SEER] and 8.2 Heating Seasonal Performance Factor [HSPF]). In addition, many homes were found to have elderly residents with wood stoves, and new heating systems and ductwork were installed in these situations as well.

A maximum of $10,000 could be used for heating/cooling system replacement and repair ($6,000 max for heating/cooling and an additional $4,000 to upgrade electrical and/or install new ductwork). Consistent with Tier 2 weatherization, heating/cooling system replacement and repair required energy usage per year to meet the following requirements:

- **≥ 7 kWh per square foot,**
- **≥ $0.23 per square foot oil/LP gas heat, or**
- **≥ $0.38 per square foot oil/LP gas heat and water heating.**

High efficiency mini splits were allowed when a home did not have a centrally ducted system or the duct repairs exceeded an estimated threshold. Funds could also be used to upgrade the electrical system or repair/replace duct systems. All of the ductwork had to be insulated and sealed with mastic. Homes also had to have been weatherized as part of the installation of a new heating/cooling system, requiring proper sizing of the system.

STUDY DESCRIPTION AND METHOD

As the Helping Home Fund was nearing completion, Duke Energy had an interest in understanding the impacts of non-energy benefits among program participants and implementation service providers. Non-energy benefits can include a wide variety of improvements, such as those to economics, health, safety, quality of life and comfort. Studying and documenting these benefits helps determine the true cost-effectiveness of home energy programs and interventions.

In performing the analysis, the first step was to narrow down the array of potential non-energy benefits to specific ones to evaluate within the Helping Home Fund. The team selected health, safety, comfort, improved disposable income, and economic sustainability/community impact.

To measure these impacts, two surveys were developed (see Appendix I). One survey went to participating homeowners, and a second survey was administered to the service providers that implemented the program measures and coordinated the work. To supplement the survey results and further characterize the outcomes of the Helping Home Fund, the team conducted a literature review to monetize the non-energy benefits. The results of this component of the program can be found later in the report.

NON-ENERGY BENEFITS

HEALTH	Health included measures such as the number of doctor's visits, decreased asthma symptoms and other homeowner health effects.
SAFETY	Safety included homeowners' accessibility or ability to move about their homes, as well as electrical and durability issues.
COMFORT	Comfort addressed whether occupants felt that their homes were more comfortable.
DISPOSABLE INCOME	Disposable income looked at whether the Helping Home Fund provided homeowners with additional income to spend on other necessities.
ECONOMIC SUSTAINABILITY	Economic sustainability/community impact included effects on service provider employment and home deferrals, among others.

PROGRAM SUMMARY

The Helping Home Fund served 3,516 homes with an average of two projects each (e.g., appliance replacement, heating/cooling system replacement/ repair, health and safety measures). Homeowner incomes had to be below 200 percent of federal poverty guidelines to participate. The homes were assessed by local service providers serving low-income customers to determine what measures were most appropriate. The work was then completed by either service provider-based crews or subcontractors.

The homes were reported and tracked on a project level. Table 2 shows the average dollars spent per project category.

TABLE 2 • AVERAGE DOLLARS SPENT PER PROJECT

	APPLIANCES	HEALTH & SAFETY	HEATING/COOLING REPLACEMENT/ REPAIR	WEATHERIZATION TIER 1	WEATHERIZATION TIER 2	TOTAL
TOTAL SPENT	$1,570,742	$2,639,385	$12,784,018	$100,217	$1,018,932	$18,113,294
NUMBER OF PROJECTS	1,676	2,731	1,878	323	488	7,096
PROJECT TOTAL	**$937**	**$966**	**$6,807**	**$310**	**$2,088**	**$2,553**

Through the heating/cooling system replacements and repairs, more than 1,300 homes went from non-functioning to functioning heating systems (Table 3).

TABLE 3 • PRE-RETROFIT HEATING BREAKDOWN OF HOMES RECEIVING HEATING REPLACEMENT

EXISTING FUEL TYPE	NUMBER FUNCTIONING	NUMBER NON-FUNCTIONING	TOTAL
WOOD	7	26	33
ELECTRICITY	410	1,060	1,470
KEROSENE	9	9	18
NATURAL GAS	1	14	15
OIL/LP	107	222	329
NO HEAT	0	13	13
TOTAL	534	1,344	1,878

Note. All heating types converted to heat pumps with a SEER of 14 or greater.

The majority of homes (92 percent) were single-family detached and mobile homes. The remaining were multifamily units and townhomes or condominiums (Table 4).

TABLE 4 • BREAKDOWN OF HOMES SERVED BY THE HELPING HOME FUND

	SINGLE-FAMILY DETACHED	MOBILE HOME	MULTIFAMILY (5+ UNITS)	MULTIFAMILY (2-4 UNITS)	TOWNHOME/ CONDO	TOTAL
NUMBER OF HOMES	2,362	858	196	67	33	3,516

PROGRAM SUMMARY

The subset of customers that responded to the homeowner survey provided information regarding the number of children, elderly, and individuals with disabilities or respiratory illness (Table 5). With these varying degrees of vulnerability, it can be difficult for occupants to stay in their homes. The Helping Home Fund was able to provide services to populations that may not have otherwise been reached.

TABLE 5 • HELPING HOME FUND SURVEY RESPONSE

OCCUPANT CATEGORY	NUMBER OF OCCUPANTS
UNDER THE AGE OF 18	112
OVER THE AGE OF 60	275
IDENTIFY AS DISABLED	237
IDENTIFY AS HAVING A RESPIRATORY ILLNESS	171

Note. Included data from 317 survey respondents.

The Helping Home Fund spending on each participating home ranged from $114.32 to $19,825.31, with an average of $5,151. Additional funding sources were used on these homes as well, including the NCWAP, PNC Home Beautification and the NCHFA (Table 6). NCWAP funds were used for heating/cooling systems and weatherization, while PNC Home Beautification focused on exterior improvement, such as landscaping, painting and roofing. NCHFA funds were used for heating/cooling systems, weatherization and structural repairs. Therefore, although a house received an average of $5,151 through the Helping Home Fund, additional work may have been performed thanks to these other funding sources.

"We are no longer cold during the winter and hot in the summer."

TABLE 6 • HELPING HOME FUND LEVERAGED FUNDS (2015-2017)

SOURCE	AMOUNT LEVERAGED
NCWAP (INCLUDES DOE WAP AND LIHEAP)	$17,321,491
PNC HOME BEAUTIFICATION	$250,000
NCHFA	$234,000

Note. Unable to obtain data for amount leveraged from other private funding.

To ensure that measures were installed correctly and funding was properly documented, randomly selected QC inspections were performed on completed jobs. At least 10 percent of homes with health and safety projects, appliance replacement or weatherization measures received QC, along with at least 25 percent of homes with heating/cooling system replacements and repairs.

QC inspectors conducted monitoring visits to evaluate effectiveness, safety, workmanship and compliance with program guidelines. They also addressed educational opportunities with local providers and customers during the on-site verification process. The process included a paper file review as well as an on-site visit with representation from a service provider. All measures installed with Duke Energy funds were verified to be present and compliant with work orders and materials invoiced. The quality of the workmanship was also evaluated, and QC inspection results were documented and discussed.

All QC documentation, on-site inspection details, reports and actions were uploaded into LM Captures. QC return visits were minimal, and all issues were addressed.

SURVEYS

The surveys sought to gauge the non-energy benefits and impacts of the Helping Home Fund. The full surveys, as well as responses from homeowners and service providers, can be found in Appendices I-III.

Homeowner Survey

The homeowner survey was designed to understand how the Helping Home Fund affected program occupants. Homeowners were randomly selected, and outbound calls were conducted by Duke Energy's call center for approximately one month. A total of 901 homeowners were contacted, with 317 completing the survey (a 35 percent completion rate).

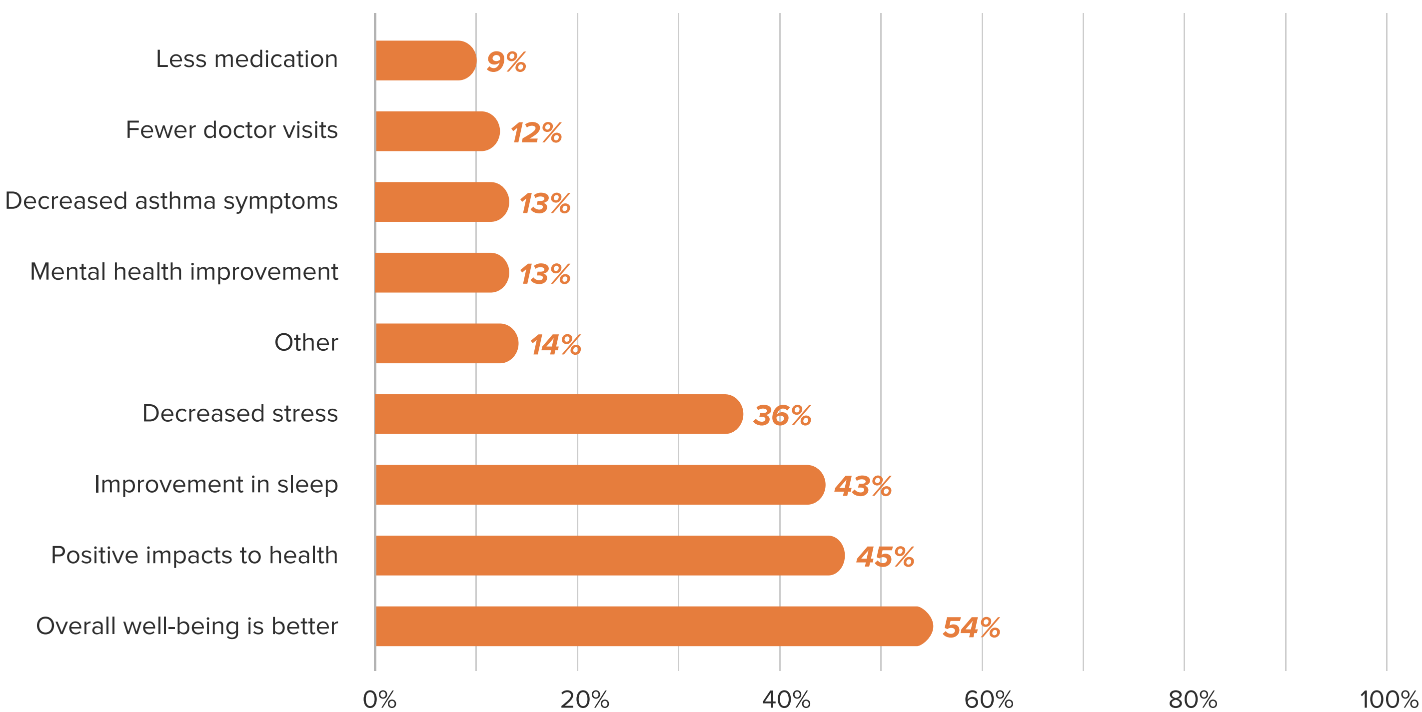
The homeowners overall had a highly positive view of the Helping Home fund. Ninety-two percent of respondents reported feeling safer in their homes, and 81 percent said they have better home accessibility (e.g., getting into and out of the home). Additionally, 91 percent said the improvements from the Helping Home Fund made it possible for them to stay in their current location, and 96 percent responded that their lives have been made easier in some form. "They did a good job and it really helped me a long way," said one homeowner. "They put windows in my home so it feels warmer and I truly appreciate everything that you all did."

> **"My light bill has been a lot lower, so that helps me have extra money. My water bill has been lower too. It has been a lot better than in years past."**

Forty-nine percent of respondents indicated that the Helping Home Fund upgrades definitely allowed them to have more money available to pay for other necessities, while an additional 29 percent said they somewhat did.

FIGURE 1 • HOMEOWNER SURVEY RESPONSES

Survey question: Have you (or any family members) noticed any positive health impacts due to the upgrades to your home? Check all that apply.

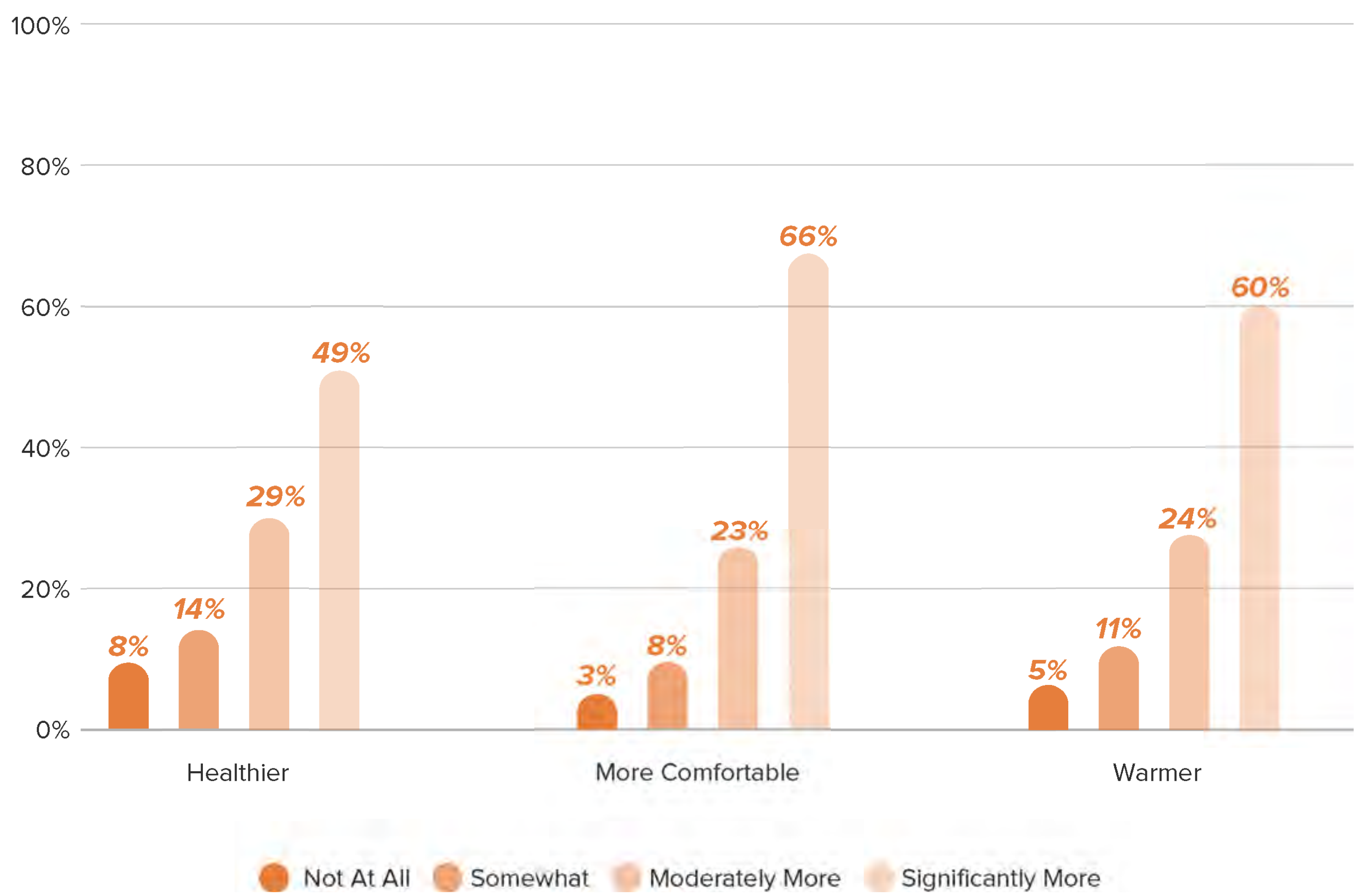


SURVEYS

Homeowners reported a number of positive health impacts for themselves and their families, including better overall well-being, sleep improvement and decreased stress (Figure 1). "If it wasn't for Duke I could still be in the hospital. Heat affects me very bad with my medical condition so to feel cooling has made a world of difference. I am now able to keep my body temperature down," reported one homeowner. Likewise, homeowners said they generally feel healthier, more comfortable and warmer as a result of

FIGURE 2 • HOMEOWNER SURVEY RESPONSES

Survey question: Are you healthier / more comfortable / warmer in your home because of the improvements made?



SURVEYS

Service Provider Survey

The service provider survey was developed to assess the effects of the Helping Home Fund on participating service providers, their crews and subcontractors, and the homeowners they served. Twenty-four participating service providers were sent the survey via email, and all responded. The service providers had a very positive view of the Helping Home Fund. They applauded the staff, communication, benefits to homeowners, flexibility and reimbursement process. According to one service provider, "Overall, (the) Helping Home Fund has been both impactful for the community and rewarding for our agency to serve others in need. We would love to be considered for future opportunities."

In particular, service providers praised the Helping Home Fund for its effect on low-income homeowners: Every provider responded that the program had a positive influence. They reported that an average of 44 percent of the homes they worked on through the Helping Home Fund would have otherwise been deferred.

Fifty-four percent of respondents felt there was a strong positive influence of the Helping Home Fund on the local community. In terms of service provider hiring, 46 percent of service providers indicated that the program affected staff employment, 4 percent said it somewhat did, and 50 percent said it did not.

The most commonly completed measures by service provider-based (i.e., agency-based) crews included insulation and air sealing, duct sealing and structural repairs to roofs, stairs, railings and windows (Table 7). Subcontractors also performed substantial work. Service providers reported that during 2015 and 2016, subcontractors were hired to help complete over 90 percent of jobs, which included electrical work, heating/cooling system repair or replacement, and plumbing (Table 7). All service providers noted that the quality of the contractor crews was either good or excellent, and most (83 percent) did not have difficulty finding contractors to work on homes. When there was difficulty, it was typically regarding electrical contractors.

"It has allowed us to serve more people in our counties that would not have gotten any service this fiscal year."

The service providers reported receiving funding from a variety of sources in addition to the Helping Home Fund. As noted earlier, more than $17 million was leveraged from the NCWAP, NCHFA and PNC Home Beautification, as well as other undisclosed funding sources. Service providers noted some variability and uncertainty in funding over the last five years. One

TABLE 7 • SERVICE PROVIDER SURVEY RESPONSES

Survey question: What measures did you install with an agency-based crew? What measures did you install using subcontractors? Check all that apply.

MEASURE	NUMBER OF SERVICE PROVIDERS USING AGENCY-BASED CREWS	NUMBER OF SERVICE PROVIDERS USING SUBCONTRACTORS
PLUMBING	2	19
ELECTRICAL	2	23
HEATING/COOLING REPAIR/REPLACEMENT	2	22
INSULATION/AIR SEALING	13	13
DUCT SEALING	13	11
STRUCTURAL REPAIRS	11	13

SURVEYS

service provider stated, “With the support of (the) Helping Home Fund, we were able to expand service delivery to Duke Energy Progress customers. Our agency’s primary funding source was limited for FY 2017; therefore, Helping Home Funds were leveraged and resulted in more customers receiving home improvements to support energy use reduction and for some improved health conditions. In addition, the opportunity to complete appliance replacement might not have happened without Helping Home Funds.”

MONETIZING NON-ENERGY IMPACTS

To get a better understanding of the monetization of non-energy impacts of the Helping Home Fund, we examined prior studies and program analyses. We relied heavily on a study conducted by Tonn, Rose, Hawkins, and Conlon (2014), which monetized non-energy benefits from the DOE WAP. This study was relevant for a number of reasons, including its focus on low-income housing and the overlap in non-energy measures being explored. It also used a robust sample size, attributing results to more than 80,000 homes.

Tonn et al. (2014) used a variety of approaches to monetize the non-energy impacts. The researchers evaluated pre- and post-weatherization survey data, relied on objective cost data from existing databases where available, and then performed monetization exercises to calculate the lifetime benefit over 10 years. The researchers categorized their results into three tiers based on the reliability of the outcomes. Tier 1 estimates were the most reliable, followed by Tiers 2 and 3. Tonn et al. also considered the value of lives saved in their analyses.

We also included data from a literature review from Schweitzer and Tonn (2003). The researchers reviewed approximately 25 articles; some were reports that presented primary research from previous weatherization programs, and others used a meta-analytic approach to examine multiple studies. This effort led to a large set of non-energy benefits, many of which were not addressed by Tonn et al. (2014). Using the available data from the prior literature, Schweitzer and Tonn selected a point estimate for individual non-energy benefits to represent an average value that could be applied to nationwide weatherization programs. In this case, monetized values were calculated using a lifetime benefit over 20 years.

Tables 8 through 12 contain the relevant non-energy benefit monetization estimates from Tonn et al. (2014) and Schweitzer and Tonn (2003). We took certain steps to err on the side of caution with the data to avoid overestimating the monetized values. For Tonn et al., we de-rated their Tier 2 estimates (by 50 percent) and Tier 3 estimates (by 75 percent). We also did not take into account the value of lives saved. For Schweitzer and Tonn, when calculating the monetized value of all non-energy impacts, we only took into account the environmental benefit associated with natural gas, the lower value, and not electricity. All estimates were converted to 2017 dollars using historical consumer price index data.

MONETIZING NON-ENERGY IMPACTS

TABLE 8 • MONETIZATION OF ECONOMIC AND SOCIAL BENEFITS

Tonn et al. (2014) and Schweitzer and Tonn (2003)

NON-ENERGY BENEFIT	MONETIZED VALUE FROM TONN ET AL. (2014) ***VALUES BASED ON 10-YEAR LIFETIME BENEFIT***	MONETIZED VALUE FROM SCHWEITZER AND TONN (2003) ***VALUES BASED ON 20-YEAR LIFETIME BENEIFT***
INCREASED PROPERTY VALUE		$244.80
DIRECT AND INDIRECT EMPLOYMENT		$1,089.36
AVOIDED UNEMPLOYMENT BENEFITS		$159.12
NATIONAL SECURITY		$436.56
REDUCED MOBILITY		$378.08
LOST RENTAL		$1.36
IMPROVED WORKPLACE PRODUCTIVITY (SLEEP)	$512.17	
IMPROVED HOUSEHOLD PRODUCTIVITY (SLEEP)	$375.44	
FEWER MISSED DAYS AT WORKS	$227.62	
WATER/SEWER SAVINGS		$368.56
REDUCED NEED FOR SHORT-TERM LOANS	$39.99	
REDUCES TRANSACTION COSTS		$50.32
TOTAL	**$1,155.22**	**$2,728.16**

TABLE 9 • MONETIZATION OF HEALTH AND SAFETY BENEFITS

Tonn et al. (2014) and Schweitzer and Tonn (2003)

NON-ENERGY BENEFIT	MONETIZED VALUE FROM TONN ET AL. (2014) ***VALUES BASED ON 10-YEAR LIFETIME BENEFIT***	MONETIZED VALUE FROM SCHWEITZER AND TONN (2003) ***VALUES BASED ON 20-YEAR LIFETIME BENEIFT***
CO POISONING*	$4.19	
FEWER FIRES	$50.04	$92.48
FEWER ILLNESSES		$74.80
THERMAL STRESS (COLD)	$194.28	
THERMAL STRESS (HEAT)	$95.79	
ASTHMA RELATED	$2,270.09	
REDUCED NEED FOR FOOD ASSISTANCE	$940.16	
INCREASED ABILITY TO AFFORD PRESCRIPTIONS	$1,090.01	
REDUCED LOW-BIRTH WEIGHT BABIES FROM HEAT-OR-EAT COMPROMISE	$55.96	
TOTAL	**$4,700.52**	**$167.28**

*Note. *CO poisoning used a 5-year lifetime benefit.*

MONETIZING NON-ENERGY IMPACTS

TABLE 10 • MONETIZATION OF UTILITY SERVICE BENEFITS

Tonn et al. (2014) and Schweitzer and Tonn (2003)

NON-ENERGY BENEFIT	MONETIZED VALUE FROM TONN ET AL. (2014) *VALUES BASED ON 10-YEAR LIFETIME BENEFIT*	MONETIZED VALUE FROM SCHWEITZER AND TONN (2003) *VALUES BASED ON 20-YEAR LIFETIME BENEIFT*
CARRYING COST OF ARREARAGES		$77.53
BAD DEBT WRITE-OFF		$121.04
FEWER SHUTOFFS AND RECONNECTIONS FOR DELINQUENCY		$10.88
AVOIDED RATE SUBSIDIES		$28.56
INSURANCE SAVINGS		$1.36
REDUCED GAS SERVICE EMERGENCY CALLS		$137.36
FEWER NOTICES AND CUSTOMER CALLS		$8.16
TRANSMISSION AND DISTRIBUTION LOSS REDUCTION		$65.28
AVOIDED SHUTOFFS AND RECONNECTIONS		$23.12
TOTAL	**$0**	**$473.29**

TABLE 11 • MONETIZATION OF ENVIRONMENTAL BENEFITS

Tonn et al. (2014) and Schweitzer and Tonn (2003)

NON-ENERGY BENEFIT	MONETIZED VALUE FROM TONN ET AL. (2014) *VALUES BASED ON 10-YEAR LIFETIME BENEFIT*	MONETIZED VALUE FROM SCHWEITZER AND TONN (2003) *VALUES BASED ON 20-YEAR LIFETIME BENEIFT*
AIR EMISSIONS - ELECTRICITY		$1,324.64
AIR EMISSIONS - NATURAL GAS		$435.20
OTHER BENEFITS		$745.64
TOTAL	**$0**	**$2,505.48**

TABLE 12 • MONETIZATION OF ALL NON-ENERGY BENEFITS

Tonn et al. (2014) and Schweitzer and Tonn (2003)

NON-ENERGY BENEFIT	MONETIZED VALUE FROM TONN ET AL. (2014) *VALUES BASED ON 10-YEAR LIFETIME BENEFIT*	MONETIZED VALUE FROM SCHWEITZER AND TONN (2003) *VALUES BASED ON 20-YEAR LIFETIME BENEIFT*
ALL	**$5,856**	**$4,550**

Note. The total monetized value from Schweitzer and Tonn (2003) excludes air emissions associated with electricity.

MONETIZING NON-ENERGY IMPACTS

The two studies reveal that weatherization and other energy efficiency upgrades can produce a wealth of non-energy benefits with values in the thousands of dollars. At the same time, it is worth noting the lack of overlap in the impacts that Tonn et al. (2014) and Schweitzer and Tonn (2003) examined. Therefore, the overall value of non-energy benefits may be even higher than those reported here.

Given the similarities in the housing stock, occupants and measures installed in the Tonn et al. (2014) and Schweitzer and Tonn (2003) studies when compared to the Helping Home Fund, it is possible to assume that participants in the Helping Home Fund received a similar level of non-energy benefits. Even with our conservative estimates, the non-energy benefits associated with the Helping Home Fund, then, could approach an average of $10,000 per home (the sum of the total non-energy benefits from the two studies). Indeed, the homeowner survey results confirm that those participating in the program did receive non-energy benefits, from health improvements to enhanced comfort and increased ability to stay in their homes. These benefits can be particularly important for occupants who are children, elderly, or have disabilities, respiratory illness or asthma.

The Helping Home Fund was not designed to reduce overall energy use but rather to provide other benefits to low-income customers, such as improved health, comfort and safety. For example, approximately 35 percent of the homes had non-functioning heating systems and the program was able to provide new systems to these customers. The program also provided new washers, dryers and room air conditioning units, since other programs typically did not address this. However, because the program highly leveraged the NCWAP, we can assume that these customers would also receive energy benefits. Based on the literature review, DOE WAP achieves average lifetime energy savings of $4,890 per home (Tonn, Carroll et al. 2014).

Table 13 summarizes the average costs and benefits for participating homes based on total invested funds and estimated benefits from the literature review.

TABLE 13 • SUMMARY OF COSTS AND BENEFITS FOR HELPING HOME FUND

	AVERAGE PRESENT VALUE PER HOME	PRESENT VALUE FOR TOTAL HOMES
ENERGY BENEFITS (COST SAVINGS)[1]	$5,115.33	$17,985,500
NON-ENERGY BENEFITS[2]	$10,312.83	$36,259,910
ECONOMIC AND SOCIAL	$3,883.38	$13,653,964
HEALTH AND SAFETY[3]	$4,775.32	$16,790,025
UTILITY SERVICE	$473.29	$1,664,088
ENVIRONMENTAL[4]	$1,180.84	$4,151,833
TOTAL BENEFITS	$15,428.16	$54,245,410
TOTAL COSTS	$10,124.37	$35,597,294
HELPING HOME FUNDS	$5,151.68	$18,113,294
LEVERAGED FUNDS	$4,972.69	$17,484,000

1. Value based on Tonn, Carroll et al. (2014)
2. Value (and subcategories below) based on summed benefits of Tonn et al. (2014) and Schweitzer and Tonn (2003)
3. Uses the lower monetized estimate of fewer fires, from Tonn et al. (2014)
4. Excludes air emissions associated with electricity from Schweitzer and Tonn (2003)

CHALLENGES AND LESSONS LEARNED

- The NCCAA was the appropriate choice for administering these funds, forming a valuable relationship with Duke Energy. The NCCAA provided access to a network of service providers who were already intricately involved in low-income communities across the state. These service providers were able to quickly access homeowners who met the requirements for participation in the Helping Home Fund. The NCCAA also saw value in being involved with individual agencies throughout the implementation of the program, getting to know their particular challenges and strengths. With this experience and data, the NCCAA is able to provide recommendations to the NCWAP to improve overall performance.

- The NCCAA collaborated with Lockheed Martin to assist with the administrative duties of the program. Lockheed Martin is a strong partner, providing invaluable recommendations for program implementation, QC and data documentation. In addition, Lockheed Martin oversaw key communication and training with service providers that kept the program running smoothly. The ability to adapt and be flexible with service providers, who had varying degrees of experience with implementing programs, was essential.

- Funding levels for individual measures (health and safety - \$800 and appliances - \$800) were initially too low, resulting in huge requests for exceptions. As a result of these requests, funding for health and safety was increased to \$3,000 per home and appliances to \$2,000 per home in 2016.

- Funding allocation for administrative costs (5 percent) was insufficient for some of the service providers; however, this could not be changed due to the regulatory filing.

- Delays in obtaining contracts and funding between the service providers and the NCWAP caused issues with completing projects in a timely manner.

- While the data collection process was thorough, some data was not collected during this initial spending cycle but was later learned through the customer surveys. In the future, the Helping Home Fund may consider including the following in data collection:

    - **Number of occupants by age group (to capture number of elderly/children)**
    - **Number of occupants with asthma or disabilities**
    - **Tracking of leveraged funds per home**
    - **Tracking of when measures are installed**
    - **Pre-retrofit survey of homeowners**

- Now that the service providers have been oriented and trained to the program, it should be less costly for them to support the program.

- Based on some of the homeowner surveys, it was determined that they did not realize Duke Energy had funded some of their repairs. While a brochure was developed and available for the agencies to provide homeowners, its use may have dwindled over time. There is an opportunity for better marketing of the program to both homeowners and local communities.

- There were mixed reviews of LM Captures, which is understandable when working with a network of providers with varying degrees of experience with technology and availability of local resources. Role-based dashboard reports provided updates for status and planning. The NCCAA and Lockheed Martin worked closely with service providers to provide one-on-one customer service and support during program launch

CHALLENGES AND LESSONS LEARNED

and throughout the program. Feedback from service providers has resulted in ongoing updates to LM Captures, including easily identified required fields, less data entry on the home page, additional options in drop-down selections and revisions to heating/cooling data entry fields.

- Programs such as the Helping Home Fund are not designed to pass energy efficiency tests. Therefore, the utility only receives funds in special cases, such as during rate cases or mergers. However, evaluating non-energy benefits in addition to traditional energy benefits can help determine the true cost-effectiveness of these programs, and allow the utility to capture the benefits such a program can offer.

- Weatherization service providers are limited in the funds they can spend on health and safety measures, causing many homes to be deferred each year. Working closely with service providers ensured that they used the Helping Home Fund monies in the anticipated manner. This funding source, along with others such as the NCHFA's Single Family Rehab program, works well with WAP so that homes can be retrofit, and homeowners benefit from access to multiple programs that can address different needs. As one example, the Macon County Housing Department "was able to use the monies from the Helping Home Fund in conjunction with other programs such as the Urgent Repair Program, LIHEAP Heating and Air Repair and Replacement Program (HARRP), Single Family Rehab Program and the Weatherization Program."

- Leveraging other programs, while a benefit, was also a challenge for some service providers. It took time for providers to learn how to effectively use different funding sources on the same homes. To help them get up to speed, the Helping Home Fund used multiple methods to train service providers, including webinars, on-site training and ongoing mentoring. Overall, they found that one-on-one training was more effective than group training. The QC field visits were an additional training opportunity for service providers.

NEXT STEPS

The Helping Home Fund recently received an additional $2.5 million when Duke Energy merged with Piedmont Natural Gas. This money will go toward a similar program and will be used in the following ways: $800 for heating/cooling repair and/or maintenance, $3,000 for health and safety, and $2,000 for appliance replacement (refrigerators, washers, dryers, room air conditioners and dehumidifiers). Duke Energy decided to reduce the allocation toward heating/cooling systems due to the limited funding, and to allow the funds to be available over a 12-18 month period.

With the success of the Helping Home Fund, the team is sharing its experience with stakeholders around the country so that others may learn from it and build upon it.

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ABBREVIATIONS AND ACRONYMS

DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DOE	Department of Energy
HHF	Helping Home Fund
HSPF	Heating Seasonal Performance Factor
LIHEAP	Low Income Home Energy Assistance Program
LM Captures	Database developed and maintained by Lockheed Martin
kWh	Kilowatt-hours
LP	Liquid Propane
NCCAA	North Carolina Community Action Association
NCHFA	North Carolina Housing Finance Agency
NCWAP	North Carolina (State) Weatherization Assistance Program
PNC Home Beautification	Fund offered by PNC bank
QA	Quality Assurance
QC	Quality Control
SEER	Seasonal Energy Efficiency Ratio
WAP	Weatherization Assistance Program

APPENDIX I • SURVEYS

HOMEOWNER SURVEY

Intro Section: (Provide context and explain the value of participating in the survey)

Hello, my name is _____ and I am calling on behalf Duke Energy. I'm calling today because your household participated in a program to receive free home improvements through the XXX Weatherization Agency. As part of this program, a contractor would have come into your home and installed free energy saving products and made home improvements. We would like to take just a few minutes to ask you a few questions.

Are you the person in your household who is most familiar with the improvements that were made to your home?

- ☐ Yes
- ☐ Don't know
- ☐ No
- ☐ Refused

We're speaking with customers who have participated in the program to complete a short survey to learn about their experience and satisfaction with the program. This is not a sales call, and all of your responses will be kept confidential.

Homeowner questions

1. How many children under the age of 18 currently live in the home?
2. How many people over the age of 60 currently live in the home?
3. How many residents in your household identify as disabled?
4. How many residents in your household identify as having a respiratory illness (e.g., asthma)?
5. Can you recall any of the weatherization improvements that were specifically made to your home?
6. Are you aware that the Duke Energy Helping Home Funds were used in your home?
7. If yes, do you know which improvements were paid for by HHF?

8-10. Are you healthier / more comfortable / warmer in your home because of the improvements made?

- ☐ Not at all
- ☐ Moderately more
- ☐ Somewhat
- ☐ Significantly more

11. Have the upgrades to your home allowed you to have more money available to pay for other necessities?

☐ Definitely ☐ Somewhat ☐ No

12. Have you (or any family members) noticed any positive health impacts due to the upgrades to your home? Check all that apply.

☐ Positive impacts to health, Less doc visits, overall well-being is better, mental health improvement, improvement in sleep, decreased stress, less medication, decreased asthma symptoms, Other (fill in the blank)

13. Have the improvements made on your house made it possible for you to remain at home (as opposed to needing to move to another location)?

☐ Yes ☐ No

14. Has your life been made easier through these upgrades?

☐ Yes ☐ No

15. Do you have better accessibility or access to your home because of these upgrades (e.g., ability to get in and out of your home)?

☐ Yes ☐ No

16. Do you feel safer in your home (e.g., from injury due to durability issues)?

☐ Yes ☐ No ☐ Somewhat

(If yes or somewhat, please describe)

17. Any other comments regarding Duke Energy's Helping Home Fund you would like to share?

That is all the questions I have today. Thank you so much for your time and have a great day.

APPENDIX I • SURVEYS

Service Provider Survey

Duke Energy launched the Helping Home Fund in North Carolina in January 2015. This fund was designed to assist low-income customers with managing their energy costs while also addressing health and safety. As the first round of funding comes to a close, we are reaching out to participating Weatherization Agencies to hear your feedback. We want to learn about your experience with the program, as well as gather data on how the program impacted local communities. We sincerely appreciate you taking the time to provide responses to the following questions.

Service provider questions

1. Contact Info:
   - ▫ Name
   - ▫ Agency
2. Has the Helping Home Fund had a positive impact on the low-income homeowners that you serve?
   - ▫ Yes, Somewhat, No
3. Have you noticed any positive effects on the local community (beyond the occupants of the homes) from your participation in the Helping Home Program?
   - ▫ Yes, Somewhat, No
4. What % of homes were you able to work on that would have been deferred because of the Helping Home Fund?
5. Did the Helping Home Program have an impact on how many staff your agency employed during the program years?
   - ▫ Yes, Somewhat, No
6. What types of funding does your agency receive on an annual basis? Check all that apply.
   - ▫ LIHEAP
   - ▫ NCHFA
   - ▫ DOE Weatherization
   - ▫ Utility Funds
   - ▫ PNC Beautification Funding
   - ▫ Private Funds
   - ▫ Other (______________________)
7. Has that funding varied over the last five years? If yes, please explain to what degree it has varied.
8. What measures did you install with an agency-based crew?
   - ▫ Plumbing
   - ▫ Electrical
   - ▫ HVAC Repair or Replacement
   - ▫ Insulation/Air Sealing
   - ▫ Duct Sealing
   - ▫ Structural Repairs (Roof, Stairs, Railing, Windows)
9. Did the Helping Home Fund impact your ability to retain an agency-based work crew?
   - ▫ Yes, Somewhat, No
10. What measures did you install using subcontractors?
    - ▫ Plumbing
    - ▫ Electrical
    - ▫ HVAC Repair or Replacement
    - ▫ Insulation/Air Sealing
    - ▫ Duct Sealing
    - ▫ Structural Repairs (Roof, Stairs, Railing, Windows)
11. How was the overall quality of contractor crews?
    - ▫ Excellent / Good / Fair / Poor (If fair or poor, please explain what was lacking)
12. Did your agency have difficulty finding local contractors to work on homes?
    - ▫ Yes, Somewhat, No
13. If yes, any suggestions of what could help remedy this situation?
14. If yes, how did this affect what work was completed?

APPENDIX I • SURVEYS

15. If yes, what type of contractors did you having trouble finding?
    - ❐ Plumbing
    - ❐ Electrical
    - ❐ HVAC Repair or Replacement
    - ❐ Insulation/Air Sealing
    - ❐ Duct Sealing
    - ❐ Structural Repairs (Roof, Stairs, Railing, Windows)

16. What percentage of jobs did you hire subcontractors to help you complete the work in 2015 and 2016?

17. If the Helping Home Fund was to be continued as a program, what improvements / changes would you suggest?

18. What worked well about the program?

19. Were there any houses or families that stood out with regard to the impact you observed from participation in the program?

20. Is there anything you want to tell us about your experience with this program?

21. Can we contact you with additional questions? If yes, Name, email address, phone number.

APPENDIX II • HOMEOWNER RESPONSES

I really like the program. Years before I didn't know about different things to make my home efficient. I have told people about it too. I feel like Duke Energy really tried to help people. Thank you so much.

I am so amazed by all Blue Ridge took care of for me with my new ac, the insulation, the moisture barrier the sensor for carbon monoxide and the replacing of my duct work. I am also happy to learn that Duke Energy had a hand in this too. Kudos to Duke Energy. Keep doing what you all doing. I have a testimony about everything that was done for me. I am so grateful. Mr. Dale and his crew were amazing. They did an outstanding job. They gave me a sense of everything going to be alright. The inspector was also great and offered his number to if anything should go wrong with my unit to call him. They did everything they said and much much more. This program is great for older disabled people like me. Anytime you need live customer data or feedback, please call me because I have nothing but good things to say about Blue Ridge and Duke Energy.

I just want to say everybody was nice and good to me. I thank you all. I love my new ac unit. I didn't know Duke Energy was responsible for doing that. I don't have to worry about that being done anymore. This is a good thing to have and I am thankful.

It was very helpful and nice to know assistance is out there for people who may be in a struggle. This is wonderful program also for older customers or those with health issues. I was more concerned with the efficiency of my home and the insulation has been great since added. I'm not worried about how often my units cycles on and off.

Everybody was so kind that came out. Very polite and were courteous to take off their shoes and not track dirt into the home. They also cleaned up after themselves. Very thoughtful. I am thankful for the good Lord to make something like this available to me. The agency also helped replace the faucets and I got light bulbs. I am very thankful for this program. I'm not sure if anything can be done or if someone can direct me, but I am in need of windows. The windows I have now are terrible. I'm using duct tape and plastic to close them shut. I would just love if someone could help guide me to a agency or a program that can help me with my windows.

I thank God for the program. Really overwhelmed with joy and happiness that there was such a program available to help me.

Appreciate this program so much. Helped me because I would have had to find another job to have to done some of the things that were done, especially the new heat pump that was installed. I was blessed with this program and to be able to qualify. I am thankful. It didn't push me into anymore debt and although I am on a fixed income at 73 yrs. old I can still pay my bills and not scraping to make ends meet.

It's the best thing that happened to me, I couldn't afford to have these structure repairs done.... wonderful thing to happen to me it's highly blessing that fell on me!!! the best thing that could have happened for me! So grateful and thankful

All of them were very nice people. I am definitely appreciative of having an electrical heating system in my house. I feel safer now since I don't have to mess with the kerosene heating and worrying about it tipping over or not changing the filter or the possibility o hit burning down more house.

APPENDIX II • HOMEOWNER RESPONSES

Where the back porch was they built steps with a handrail... I was very appreciative, I needed the work done and had no idea how I was going to do it, I was so happy to qualify for the program.... it was a blessing.... I said my prayers and this happened... I really appreciate it....

I am so grateful.....when the contractors came out to my house - I cried.... I was so thankful..... I just want to thank everyone at duke energy from the bottom of my heart!! I don't have to worry about spinning my air unit by hand....it would freeze up and we would have to cut it off by the breakers.... old a/c unit finally stopped running... I had everyone in my family send a letter to the agency thanking them for everything....I send them Christmas cards, send them thank you notes.....

I thought my light bill would come down....but it hasn't.... put insulation in the roof, I appreciate all of the improvements that were done..... thankful for the help.... did a lot of work....

I appreciate the program and I would recommend it to anyone. You guys did such a wonderful job, from the bottom of my heart.

I'm so grateful...I. would like to say thank you from the bottom of my heart... it was getting to the crisis mode where I thought I would have to move..

They put insulation in attic, fixed heat ducts so heat would go down... it's a good thing to help people, it's a good fund if people don't have the income to put stuff in...it's good.

The contractors that were used were excellent, the approach, communication, they were a great group.

I would like to say thank you for the program, its been a life saver...

I think this is a great program. It helped me and my family. I hope more funding becomes available to help other families.

I must say that everyone who came out I was well pleased with. They were all kind mannered and promised to be here and was here at the time given. I am very happy with all things done and happy for my new ac unit. The guy who installed my new system explained everything to me very well.

The crew was great. I hope Duke will be about to continue this service. It has a lot of benefits to the community and I appreciate being able to have had the opportunity. I was out of work during the time my new system was installed so I am thankful. This program is one of the Best programs Duke offers and is an excellent service.

I am surprised that they were able to install my new heat and cool unit in my home because I have an old mill house so I am very grateful that they managed to install it. They did a great job. Everyone was nice and cleaned up after themselves. The inspectors were nice too. I wish I had money to contribute to this fund to help others in need because it is hard when you need improvements and don't have the money or means to pay for it. I am thankful Duke has a program like this and the weatherization agencies.

APPENDIX II • HOMEOWNER RESPONSES

I just think is Godsend. It is such a wonderful program for senior citizens, someone who is disabled that cannot afford to help themselves.

I'm on equalized payment and my bill went from 193 to 120 dollars per month... that extra savings can pay for another bill... I was flabbergasted when I qualified for the program, my heat pump was replaced, washing machine is great, (this machine wrings out clothes so less drying) replaced every light bulb... they were fabulous, couldn't believe it... I work at a non-profit organization, it was unreal, it I hadn't been worked there i wouldn't have known about the program.

Power bill has gone from 500 to 200 dollars per month. We were using space heaters to heat the home & a window unit to cool the home. I'm 100% satisfied that they helped me as much as they did!

My mother doesn't have to worry about buying oil this winter or using a space heater, which is dangerous. Many people do not know about this program and its because of the line of work I am in to why I found out. This has been a life saver. I do not live with my mother but my brother and I were there when everything was being done and I don't know what we would have done without this program because financially we don't have the money to have made these sort of upgrades. My mother is elderly and it gives her now a sense of being safer, warmer and saving money. She can also stay in her own home and not in a living facility. This program saved our lives and we thank you so much.

Having the new windows make me feel safer. Overall I feel better and I am grateful and thank you all.

It was just wonderful and I thank and appreciate it. It's fantastic that Duke can set aside funds to help people like myself that is on a fixed income and elderly. I am a widower and I can't thank you all enough for my new air conditioning system. I am very appreciative of everything and Duke.

The program has done a lot for a lot of people in the neighborhood. I hope that the program continues and help others. My light bill is very very good. I really enjoy the way it is. I hope they decide to do more of this program, especially for senior people who can't afford it. It really came in handy.

It's a great program to help people. I always worked and made it on my own and I have been very independent and then had a lot of medical issues. I have been in a pretty bad shape, and my stuff went out, so I was glad for that program.

I think is a great program for people who really need it. Sometimes is hard to make meets end, so anything that you can do to lower the electric bill, so I think you should do more of these programs.

I really want to thank you for having the program. It helped very much. I am in a lot of medications, so this helped me a lot. I have told people that Duke Energy helped me a lot and that's why I feel better. My bill also decreased and is very nice now.

The whole process was painless. I couldn't have asked for a better set of people. Mark and David were exception. They were great. Neat and courteous. I was so appreciative I cooked them a little something to say thanks.

APPENDIX II • HOMEOWNER RESPONSES

I never knew that Duke Energy was involved. The people that worked on the house they were some of the best people ever. The people that were hired were great people.

I think the program is amazing, for citizens who pay taxes like myself. These improvements allow me to tell others about this program. It's great. I am truly blessed.

They did so much!!! I think it's a real good program who need assistance.. when winter comes I'll really get the benefits.... appreciate the program, a really good program.... the people who administrated the program did a great job! They let me know all of the information.

I just think the program is wonderful. They did so much for us. Me and my sister live here and we are getting out there in age, fixed income, and we couldn't have done any of this without you guys. We don't have to worry about things breaking down. We know that we will be able to stay here for a long time. It is just wonderful!

They all did a fantastic job with the upgrades. After they finished my evaluation my refrigerator went out 4 days later, and it wasn't included.... thank the lord for that program and I was eligible for it. it's a great thing you do for people who can't afford those things, i don't know what i would have done... all the guys were very nice and friendly and everything I'm glad to be a duke energy customer.

Thanks a lot, if it weren't for the upgrades I don't know what me and my mom would do, keep the program going... most definitely... if you can help anybody else like you've helped us, please continue. It was amazing for us!! It was an amazing experience.. the people that did the work were very considerate of me and my home...

I think Duke Energy is good, everything is great, all the upgrades, I couldn't ask for anything any better thanks to duke power, what would we do without them.

Door is a lot more secure, windows are more secure.... previously on windy days you could actually hear the wind blowing inside, it was so bad the wind would move the blinks... there was a lack of sealing previously... I'm glad to know Duke Energy was behind a lot of it.... this place really needed it (public housing).

I think it is a good program for people that are on social security and can't afford big bills. Everyone who came out was really nice and I thank Duke Energy for helping me.

The little boys that the installed the equipment were really nice, they did a good job.. Ms. Cannon wanted to make sure everyone got involved with the installation got an A+ After my a/c was installed I told my girls "I believe I've went to heaven when I woke up."

It has made a world of difference... wasn't aware Duke Energy HHF was involved.. couldn't believe I was eligible for all this equipment... I want to thank Duke Energy for being a company that has helped a consumer, feels very very good!! Absolutely remarkable...

APPENDIX II • HOMEOWNER RESPONSES

Don't have to use plug in heat, feel safer now.... not worried about fires as much, fire/gas alerts system make customer feel safer... Duke Energy has done a wonderful job to help the seniors, a lot of customers can't afford a heating/cooling system, we didn't have the money to put in heating/cooling system. The people who installed the system did a good job, cleaned up before they left.... appreciate washer/dryer, appreciate that..... customer really appreciates everything to the highest...... they removed a lot of stuff from the bottom of the house and they had it all removed... can't complain about any of the services.

Feel safer in home because old heaters were bought from Walmart and they weren't as safe. The HHF has been a blessing, it has made our lives so much easier... Hopefully others can benefit from this program... our electric bills have been cut in 1/2...

I appreciate everything that was done. I appreciate it so much that I wrote thank you letters to everyone with Community Action Opportunities. I am very thankful. I used to burn oil and I didn't have to spend the money this year. They also upgraded my wiring to get the new heat pump in. They took good care in what they did and with me.

I am glad that Duke Energy had the funds to help and assist the disabled. It helped me tremendously. It has helped my bill a lot. It has decreased my bill for about $100 or so.

I am just glad that it was available and we qualified for it, for our HVAC. It was really expensive for us because of kerosene.

I am so thankful for everything that was done for me. Everyone who came out from each of the companies were very professional. Even the Inspectors were nice and not snobs. They assured me that all the electrical work was done correctly. They even installed a smoke and gas detector alarm.

I appreciate the new appliances, because they are more energy efficient. I know down the line they will help me with the electric bill. I greatly appreciate it.

Customer says he and his mother are on disability and it was blessing, and they really appreciated what Duke has done for them.

My personal opinion, I think this program is a blessing. I think that DE is one of the most wonderful companies to help people who are disabled. My husband passed away last year from cancer and this program helped me so much. I am so thankful.

I am greatly thankful for Duke Energy and this type of program. I was in shocked that I could apply and actually got accepted. They replaced my washer and dryer and my ac unit. They also gave me a refrigerator. My house was hot and moldy previous to the improvements and had deteriorated and had critters. I feel healthier overall. If it wasn't for Duke I could still be in the hospital. Heat affects me very bad with my medical condition so to feel cooling has made a world of difference. I am now able to keep my body temperature down. This is a mobile home so it isn't very efficient to begin with. Thank Duke and the weatherization Action Pathways for everything.

Everyone that was sent out was professional from start to finish. From the first inspector to the final inspection inspector. This was very convenient and mindful and everyone was friendly. Definitely keep

APPENDIX II • HOMEOWNER RESPONSES

this type of system around. I hope it can extend across the nation to others in need. I recommend it. Sad to hear that our fearless leader is trying to take programs away like this but I am grateful that it is available. Thank you so much for taking the time out to call to ask about my experience.

I would tell anyone that has the opportunity to do this to please do it immediately. Be careful who you said yes to, but if you know if it is a program that Duke Energy is responsible for, then they will take care of you.

I can breathe a lot better. You all did such a good job. Thank you all for doing this. I am so pleased. Everyone was so nice and the entire thing was enjoyable.

Keep program up. Elderly people need it. After you work all your life then to end up on a fixed income it's hard when things need to be fixed. Sometimes you have to choose to do without meds or maybe food depending on how bad it gets. I thank you all for doing this and keep it up.

Thankful for heat pump and thankful overall for everything that was done and is coming out to her home. During the winter customer feels a lot warmer and during the summer hot months she is a lot cooler. She has noticed breathing better although she doesn't have an issue breather. The quality of the air is better. In the past she has used fans but now feels better overall during the hot days.

If it wasn't for Duke Energy I don't know where I would have been this winter. With previously having to use a wood burner for heat which caused my sons breathing issues I am thank you to Duke for installing a new heat and cool system. I am tickled to death and so pleased of all the work that was done. I am so happy that Duke cares about people who need help and from the bottom of my heart I am thankful.

I was not aware Duke Energy money was used towards the improvements in my home so knowing this is great and I appreciate you all so much. I also like the tips you send out on think that can be done in the home to save money like hanging the clothes to dry instead of using the dryer.

I sure appreciate the things that were done because it helped to better the household. To have a better heating and cooling unit helped a greater deal. They also did the cracks and the bathrooms which was good too.

I have nothing negative to say about my experience. The air conditioning company (Mr. Richard) was awesome. Make note that Mr. Richard explained that this was one of the biggest jobs they have done. It was starting from scratch. No insulation in the attic, no central heat or cool. They also added vent in bathroom and a main breaker. I am so very grateful and thankful and happy to recommend this is anyone I know. I had to wait 2-3 years for this and I am thankful my home had all these improvements made. Tell the program manager that this was exceptional for Duke and the other workers to do.

They did a good job and it really helped me a long way. They put windows in my home so it feels warmer and I truly appreciate everything that you all did. One person in here asthma is as bad and overall we feel good and is comfortable. Thank you so much.

APPENDIX III • SERVICE PROVIDER RESPONSES

WARM was able to assist so many families with these funds. We are so grateful, and wish there were more funds to continue to help so many more families that are in need.

We worked very hard within a short time frame to spend the original allocation, plus the additional funds we requested and received. In about a two year period, we installed over 175 heating systems, a great many appliances, and health & safety and weatherization measures. In spite of all that was accomplished, the need exists for that much more to be done.

It has been an great program for all our eligible clients.

We look forward to continuing to work with Duke, it has been an outstanding opportunity for our agency as well as the customers that have been touched by this program. It has given us the opportunity to bundle services with other agencies to serve customers and provide additional measures in the home.

This was a great program, but the need is still great (10x).

The program support team was very helpful in assisting us from the start to finish and we were able to leverage the funding to provide needed services to the low-income folks CADA serves.

This was one of the best programs we have administered to assist homeowners with appliances. (2x).

The staff at NCCAA and the Martin group were very helpful and easy to work with. The requests for exceptions were processed quickly as were agency reimbursements. This program was a win-win for all involved.

Overall, HHF has been both impactful for the community and rewarding for our agency to serve others in need. We would love to be considered for future opportunities.

Joel Groce with NCCAA did an outstanding job administering the dollars.

This has been a great program. The Duke HHF staff were great and very knowledgeable. Payments were also processed timely.

The HHF program has helped offset many program expenses and has allowed us to continue working longer through the year until the new contract is completed and/or funding is released.

CONTRIBUTORS

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Testimonials

[redacted]

[redacted] is a Columbus County resident that applied for weatherization due to the high cost of heating and cooling her home. [redacted] qualified for the HVAC replacement program through Duke and was able to get an energy efficient heat pump installed. [redacted] stated, “I don’t have to seek assistance anymore with filling my tank to heat my home. I am very pleased with all of my services.”

Old Unit

New Energy Efficient Unit

Non-Functioning CO Detector

New CO Detector

Old Thermostat

New Energy Efficient Thermostat

Helping Homes Fund gives Hickory woman her first heating and AC system …

By KJ HIRAMOTO khiramoto@hickoryrecord.com
Sep 9, 2016

Janet Lutz of Brookford adjusts her thermostat to her new heating and cooling system from Duke Energy's Helping Home Fund.

Janet Lutz of Brookford has already started covering her new refrigerator from Duke Energy’s Heling Home Fund with photos of her grandchildren.

HICKORY – The thermostat at Janet Lutz's house in Hickory has remained at exactly 72 degrees Fahrenheit throughout the summer. While Lutz insisted she is comfortable with the temperature setting in spite of some of the hottest and most humid days during previous summer, it was also due in part to her being overwhelmed by the technology.

"I'm scared to touch the buttons," Lutz said jokingly. "But it feels great around the house. … My sister also told me to keep the fans in the living room going to keep the air flowing."

Before having the thermostat installed in her house, Lutz had never owned a heating and air conditioning system.

"I've always had my wood stove for over 40 years," Lutz said. "I made my boys go out buy a loaf of wood, stack a pile outside, bring some inside the kitchen and we'd heat it with a stove."

Thanks to the collaborative efforts between Duke Energy and Blue Ridge Community Action (BRCA), Lutz's days of making her grandsons gather wood to generate heat around the house is over.

Lutz was among the families selected by BRCA as one of the recipients of Duke Energy's Helping Home Fund.

Helping Home Fund is a program that offers free assistance for income-qualified Duke Energy customers with up to $10,000 in energy efficiency upgrades. After receiving a complete home energy assessment, they also receive assistance and counseling to help the families save on their future energy bills.

BRCA's role is to administer the home improvements for the chosen Duke Energy customers as soon as the non-profit organization receives the allocations from Helping Home Funds. They identify the clients who apply for the program, send out contracted auditors to test the home then the auditors send the reports back to BRCA, which then follows up with a select group of clients based on their eligibility scores.

BRCA Energy Director Shawna Hanes said the program operates in a team effort with all the contracted partners and Duke Energy all playing their own roles.

"We have qualified contractual partners that we had carefully selected which we are glad to have with us," Hanes said. "And we would not have been able to install the system (in Lutz's home) if it weren't for the funding received by Duke Energy."

In addition to assessment and counseling, chosen families like Lutz's receive services from the program such as health and safety repairs and installation of home ventilation systems.

And for Lutz's case, she received repairs on her home windows and a refrigerator as additional services provided by the program.

Lutz said ever since the installations for the series of home improvements were completed several months ago, she had been pleasantly surprised to see her house is a lot more energy efficient, evident by the noticeable difference in her monthly Duke Energy bills.

"When we used the wood around the house, it went around $200 a month," Lutz said. "Now it's between $120 to $140. … Now I can spend the extra money on the boys' school supplies and (school) uniforms."

Lutz said the new heating system in the house has enabled her to give her two grandsons -- Daniel, 15, and Nick, 11 -- extra time in the evenings by not having to make them go out to gather wood for the stove. But as a result, she did add more chores around the house for the boys.

“They’re not going to sit around,” Lutz said jokingly. “Daniel likes to cook so I have his prepare the main dishes, and Nick likes to bake pastries and I get him to organize the Bible shelves.”

All jokes aside, Lutz said the series of home improvements and installations have helped the family immensely, especially for her two grandsons. They've struggled with asthma when their house was in its previous conditions.

“They’re nowhere near as affected by it now,” Lutz said. “I couldn't be more thankful for Helping Home Fund.”

Hanes said seeing the families experience improvements to not only their home utility systems, but also to the quality of their lives makes her job that much more fulfilling.

“It’s always exciting to see all the work get done,” Hanes said. “It keeps our staff motivated when they get a chance to see these families smile in-person.”

Application Process

Although BRCA is nearing the end of its Duke Energy HHF allocation period, Hanes said she encourage clients to apply for services since they will continue to provide weatherization services to low-income families. Hanes said if a client is unable to come to the BRCA office locations, our organization’s service workers could make a home visit when possible.

For more information on the weatherization services, visit their website at http://www.brcainc.org/weatherization. The Weatherization Services page provides more information about how weatherization helps low income families save energy and money and also informs clients on how to qualify for weatherization. Applicants must qualify for weatherization in order to qualify for the Duke funds.

Duke Energy's Helping Home Fund aides Lincolnton woman

MATT CHAPMAN
Staff Writer

Duke Energy launched its Helping Home Fund in January of last year and has since provided more than 2,000 families in North Carolina with up to $10,000 of energy efficiency upgrades at no cost to the customer.

The Helping Home Fund is a $20 million program funded by Duke Energy shareholders that was authorized through an agreement with the N.C. Public Staff and approved by the N.C. Utilities Commission in 2013. It serves families at or below 200 percent of federal poverty guidelines and helps income-qualified customers with upgrades that include the replacement of outdated washers and dryers, HVAC replacements, insulation and other weatherization benefits.

Duke Energy contracted the N.C. Community Action Association to administer the $20 million of funding through 28 agencies across the state. In Lincoln County, more than $58,000 from the Helping Home Fund has been administered through I Care Inc., a private non-profit that works to expand economic security for vulnerable families.

Patrenia Fair is one of the Lincoln County residents who has been helped by this collaboration between Duke Energy and I Care. She spent years living through sweltering summers and harsh winters in a home without a properly functioning heating and cooling system. Fair lacked the disposable income to make the required fixes and the problems snowballed as the use of space heaters and window air conditioning units drove her energy costs through the roof.

“I thank God for these people who have helped me,” Fair said while fighting back tears. “I’m glad that they came by to see about me and cared enough to come check on me.”

Fair applied for the program through I Care and as a Duke Energy customer was eligible for assistance through the Helping Home Fund. Work began on her home in April as I Care replaced her electric baseboard heating and installed a brand new heat pump. In addition to the new heating system, Fair’s home also received weatherization upgrades and the fund provided her with a new, energy efficient refrigerator to help save additional money each month.

“I’ve been in this job for almost seven years and I’ll never forget the first home I went into,” Rick Stotts of I Care said. “It was a mobile home and it was in the winter time and it was freezing cold in there. I saw this young girl laying on the sofa with a bunch of blankets over her and I didn’t realize it right away, but she had a little baby under there trying to keep it warm. I have a real soft spot for older folks and kids. They’re so appreciative for what you do for them and you can see the difference it makes in their lives.”

The Helping Home Fund is a one-time program, meaning that once the $20 million has been spent the program is over. However, Duke Energy representatives are working on putting a similar initiative together sometime in the near future

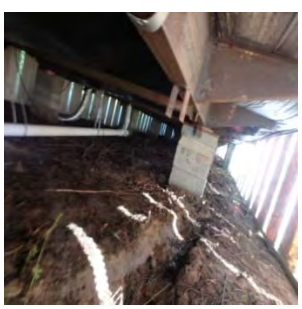
“We are a very large company, but we want to try to reach out to everybody and have a conversation,” Duke Energy program manager Casey Fields said. ”If it means that we can make a big enough change in someone’s life that you get emotional or you feel good about it, it makes my job much, much better at the end of the day. This is a phenomenal program and this is the right thing that we’re doing and it’s what we should be doing.”

Image courtesy of Matt Chapman

The customer was in need of energy saving measures for his mobile home. He is disabled and has limited income, which made it difficult to get much needed measures done to his home. [redacted] was grateful for all the assistance that Action Pathways along with Duke Energy's Helping Homes Funding provided to his home. [redacted] was very pleased with all the services he received by from weatherization program and has already seen a change in the way his home feels.

[redacted]'s Home

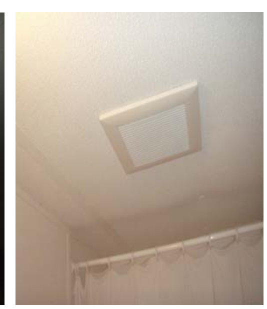
Old System New Energy Efficient System



No Vapor Barrier

Vapor Barrier

Old Bath Fan



New Bath Fan

Since the start of the Duke Helping Homes program we have helped over 125 families in Macon County addressing health and safety issues and installing energy efficient appliances and heating systems to reduce their energy usage and monthly bills.

The health and safety part of the program enabled us to install handicap ramps, grab bars and do much needed porch repairs so that our clients could stay in their homes. Also we were able to install new heating and air conditioning systems where they were non-existent or beyond repair. This was so very important to our clients on oxygen and with health issues.

[redacted] is one of our clients with health issues and cannot endure extreme cold or heat. She is very comfortable in her home now with her new heating and air system and does not have to go stay with relatives as she did in the past.

[redacted] is a client who is on oxygen and installing a new heating and air system to his home eliminated the wood burning stove. He could no longer lift the logs and a dangerous situation was eliminated.

[redacted] was in a nursing home and could not return home until a handicap ramp was installed. She is now able to be in her own home.

[redacted] was in desperate need of a handicap ramp and since his wife is on oxygen, we were able to replace the propane system with a heat pump and install the handicap ramp.

[redacted] was in need of porch repairs and a handicap ramp. He is now able to enter and exit his home safely and can stay there for many more years.

[redacted] **and his wife** are both disabled and have a young child. They are truly grateful for the handicap ramp and heating and air system.

[redacted] lives alone in a very rural area and was in need of a handicap ramp. She was in a nursing home and couldn't return home. We were able to install the needed ramp and also install a mini split heating system for her. She is now able to be at home.

So many of our clients have commented about how their lives have been changed for the good and how happy they are to see the reduction in their energy bills due to the appliance replacement program and HVAC replacement program.

Macon County Housing Department was able to use the monies from the Helping Home Fund in conjunction with other programs such as the Urgent Repair Program, HARRP, Single Family Rehab Program and the Weatherization Program.

We wish the program would be continued as there are many elderly, disabled and single parent families here who would benefit from being able to switch from wood burning stoves and the expensive propane heating to the energy efficient heat pumps.

Various Success Stories from Duke Energy's Helping Home Fund

[redacted]
Wilmington, NC

To Duke Energy Helping Home Fund:

How will I ever be able to thank you for kindness & generosity in helping us to get a new HVAC system put in. After living over a decade without heat and air, it had pretty much become a way of life for us to live in one room during cold and hot days. Using an electric heater to stay warm was neither safe or efficient. As students (trying to improve our lives) we would sit and do homework with hat, coat, & gloves on. For us, it was a normal way of life for many years. However, thanks to your Home fund and giving back to the community, Wilmington Area Rebuilding Ministry, Inc. was able to see to it that we were matched with you to be a recipient of your gift. It has changed our life overnight to have this new system in place. Thank you again and WARM for your kindness & especially for the volunteers at WARM for treating us with dignity & respect.

[redacted]
Durham, NC

[Received Air Sealing and Mechanical Ventilation]

This letter is to thank you for the amazing and wonderful maintenance work that was done to bring my home up to standard. I would never have been able to pay or save for the service that Your Company did for me. The company is a God Sent for Seniors.

I would like to thank the people (men) who performed the service, they were [redacted], the Auditor, [redacted], and the other two men from Charlotte, NC who did the electric work. They were very polite, friendly and respectable to me and my home. After the work was completed they checked to see if everything was working or performing correctly.

Again, Thank all of You.

[redacted] [HVAC Replacement]

To whom it may concern. We just wanted to thank you for all you did for us. We could not have afforded this ourselves. It's good to know that in this messed up world we live in today, there is still people with goodness in them. I believe God will bless and prosper your company for what you do. We appreciated all your crews that came out. God bless you and good luck in the future.

[redacted]
Willow Spring, NC
[HVAC Replacement – Mechanical Ventilation]

Thank you for the weatherization of our home. The things did have definitely made a difference in our electric bill. We are so appreciative for the services that you provided because they were needed so badly and we could not afford to have any of the work done.

The gentlemen from your organization and the service providers from Therma Direct, Carolina Weatherization, and Lowe's were so respectful and extremely courteous.

[redacted]
[Plumbing repairs & HVAC Repairs]

Wanted to say thank you so very much for help in facilitating all the repairs on my home. Already seeing a difference in energy bills. I have nothing but good things to say about your agency. Hope you all keep up the great work.

[redacted]
Zebulon, NC
[HVAC Replacement]

My deepest appreciation to all administrators of Wake County Weatherization and Duke Energy Progress Heat/AC Assistance Programs. Because of your programs, I was blessed to get my Heat and AC needs met for only 25% of the total cost which was paid by my landlady.

[redacted]
Henderson, NC

I would like to express my appreciation for this program. It has really helped me a lot. I would not have been able to have this work done without your help. My house has never been better.

The works were very professional and kept me informed on what was going on. They had to rework the duct work, install insulation, replaced attic steps, replaced roofing (ceiling tiles) and installation of the unit. There "wore" the best. Without this program, a lot of families would be without heat or air and a comfortable place to live.

[redacted]

Just wanted to thank you and let you know how much I appreciate all that you all have done for me. The heating and cooling unit works great, and the washer and dryer are great, makes doing laundry a pleasure. All who came to my house to install everything, were so very very nice. I have never had that many new things that I didn't have to make monthly payments on. What a blessing.

Homeowner serviced by Coastal Community Action in New Port, NC

[redacted] [Executive Director of Coastal Community Action] called this morning after receiving a call from a lady who had been helped through the Helping Home Fund. This lady was a retired teacher who because of sickness was no longer able to work. She had replaced the roof on her home before her funds ran out. She has been without heat for a very long time. The actual work will not be completed until tomorrow, but the lady was so overwhelmed with the kindness shown to her that she called [redacted] and talked for over an hour. She said that she had never been treated as kind and was so appreciative of the professional staff at Coastal.

[redacted]
Mount Airy, NC

Dear [redacted]/Weatherization and Duke Power, Just a note to say THANK YOU, so much, All of you, for my new A/C unit and the free installation of same. I've worked hard all my life and it is so much appreciated. To find people willing to help me so much in my older, non-working time and age. And what a year to get such a blessing – So hot!

[redacted]
Fuquay Varina, NC

I just had to thank you and your company for caring about our community and seniors. I have been so afraid of falling "again" in the winter with 2 inches of ice on my stairs, not even able to get out of my home. Through the money you gave to Senior Weatherization I am now much safer going in and out of my home. I am more than grateful for your helping me! I will be praying for God's blessings to overtake you and your company and your family.

You truly have been used by God to answer my prayers to keep me safe Thank you one million times

[redacted]
Charlotte, NC

I wanted to take this time to thank you for your service in making sure I have received my new GE Appliances, what a difference it has made in my home. Having appliances that are not only brand new, but are updated and just simply beautiful.

Thank you for your Help and the Change it has made in my life.

[redacted]
Raleigh/Durham

Season Greetings,

I did not want another day to go pass without me giving you all this big appreciative love email!! I am speechless and so grateful for all the work that was done to my home! I came to you will lots of concerns and not to mention a $1200.00 light bills for two months. My family barely made it through the year because there was only money for the basics but God!!! There was no way I could have ever afford to do any of the work you all did! I am less stressed because my power bill has been cut down tremendously, we all sleep safe at night because you have installed smoke detectors and carbon monoxide detectors, I won't have animals crawling in the crawl space and it was fully insulated as well, and although it's not the last thing you all did but you all got rid of my 1980s refrigerator and blessed us with a new one. I am emotional right now just writing this email! If I ever was wavering in my faith, I am reminded every time I opened the front door and step inside my warm and cozy home 2 things-God has angels on earth and He is still performing miracles.

[redacted]
Boonville, NC

From the agency that served [redacted]

I had a delightful telephone call from [redacted] and wat to shar it. [redacted] is an elderly lady. She's an expressive person and has a jolly attitude and outlook about most things.

She called me to let me know Lowe's delivered her new refrigerator at 8:08am Tuesday morning. She said she "had no idea it would be so big and so pretty and so nice! That's a rich lady's refrigerator! I have never had a refrigerator I didn't have to buy on credit, make payments on, and do without, in order to get it. I'll be 83 next Wednesday and I think this is my birthday present from heaven! I don't know if other people call you to thank you for their refrigerators and let you know how nice they are, but I had to. I want to thank each one of you that had anything to do with helping me get my new refrigerator and heat pump. My house is nice and warm now!"

Success Story from Charlotte Area Fund

Good Afternoon [redacted],

I really did not know what I was going to do! For almost 5 years, my washing machine had been leaking, it took more than 2 hours for 1 load of clothes to dry, my refrigerator made a "humming" noise, and my oven door was broken.... the whole house was falling apart and honestly so was I!

I was barely making enough money to survive and just the thought of trying to replace worn out broken appliances was almost too much to bare. And then.... I read the article in the *Charlotte Area Fund Spring 2016 Newsletter* about the Charlotte Area Fund and Duke Energy Replacement Appliance Assistance Program and like an **angel** you helped a struggling resident obtain new appliances!

[redacted], you made the process so easy, you completed the paperwork quickly, and you were very professional. The contractor and the delivery personnel you sent to my home were extremely professional, courteous and completed the job in a timely manner. I thank the Good Lord for this program. I can now cook in a new modern oven, wash my clothes in an energy efficient washer and it only takes about ***15 minutes for a load to dry!!***!
I am so overjoyed at receiving these appliances words can hardly express my joy and gratitude!!

Thank you so much [redacted], the Charlotte Area Fund, and Duke Energy for this awesome program.

God Bless you once again.

POSTED ON SEPTEMBER 7, 2016 BY STOKES NEWS

Couple benefit from Duke Energy's Helping Home Fund

By Amanda Dodson - adodson@civitasmedia.com

Anthony and Lydia Prysock, a retired couple living in the Walnut Tree community, were the recipients of home upgrades through Duke Energy's Helping Home Fund.

Anthony and Lydia Prysock, a retired couple living in the Walnut Tree community, were the recipients of a new high efficiency heating and cooling heat pump, a washer and dryer, and safety measure upgrades to their home through the Helping Home Fund. The two-year initiative, launched in January of 2015 by Duke Energy, reduces the burden of energy costs and electricity for families in North Carolina. The $20 million community investment pays up to $10,000 per household for repairs, new appliances, retrofitting for efficiency, and other electricity costs based on household income.

Last winter, the Prysock's were paying nearly $400 a month using baseboard heating, a grueling amount for the couple who are on a fixed income. While they've slowly completed home renovations over the years, there was a mounting list of more to do.

"I noticed one of my neighbors down the street was having a heat pump put in and I asked the contractor to write up an estimate of how much it would cost at our house," Prysock said. "But as I was talking to the young lady, she told me about this program and I gave them a call."

After doing some research, Prysock realized he and his wife were eligible for Duke Energy's Helping Home Fund, and the program would easily cut his power bill in half.

"We applied and went through the process. I'm really thankful for this and for Duke Energy giving to our area. This is how you rebuild communities. What little money we did have we redid the cabinets and put on a new roof. It would have been a long time before we could have done anything like this."

The Helping Home Fund has invested over $175,000 in Stokes County and helped 55 families receive energy-saving upgrades at no charge to income-qualified customers.

"The Prysock's are one of more than 2,000 families we've helped all over North Carolina. We've spent almost $10 million dollars and we still have about another $10 million," explained Lisa Parrish, Duke Energy's Government and Community Relations Manager. "We have great organizations we work with like YVEDDI that just know how to get it done."

Tommy Eads, the weatherization director from YVEDDI, said the program has been flooded with applicants and said when considering homes, they look at household size, yearly kilowatts usage, and income.

"We've done several houses on this street and some others close by. There's 334 projects that we have either started or completed in homes from Stokes, Surry, Yadkin and Davie. We service all four counties with the state and the Duke Energy program," Eads said. "It's great to be able to help the community. I feel like we get to be a part of making a difference one homeowner at a time."

Amanda Dodson can be reached at 336-813-2426 or on Twitter at AmandaTDodson.

June 12, 2015

Governor Pat McCrory
Office of the Governor
20301 Mail Service Center
Raleigh, NC 27699-0301

Dear Governor McCrory,

My heating and air conditioner quit working in January. I purchased some little heaters that kept me warm. I was employed for many years and was a single parent of two children. Unfortunately, I had to retire sooner than expected and being independent made that a hard transition. I called several companies for estimates and realized faith was my only solution. My daughter contacted an agency by the name of Coastal Community Action Inc, specifically its Weatherization Assistance Program and the Heating and Air Repair and Replacement Program. It was an answer to prayer! I called and spoke with [redacted] at Coastal Community, and she had me send in the necessary paper work to see if I qualified. She was very kind and helpful. My daughter had originally spoke with her boss, [redacted] and he talked with me and was very helpful, explaining the process that would take place. Next [redacted] the auditor, came to my house to inspect my whole house to see what could be done to weatherize my home. He was very precise checking throughout my home, and he explained how different things would be beneficial. I called and talked with [redacted] who is in charge of the whole program. She told me something that really stuck in my heart. She had presented a three hour presentation to get the funds and grants to help people. I had much gratitude that she had accomplished receiving the grants that would be a gift to so many people. I have never received such help so I am very appreciative. Then they sent the crew out to weatherize my home and to put in an exhaust fan, to wrap my hot water heater, to put a new shower head on, and carbon monoxide detection. They also put insulation around the duct work. These guys were very mannered and it was obvious there was great team work. These guys were [redacted], [redacted], [redacted], [redacted]. [redacted] came to inspect their final job. These guys were awesome!

Coastal Community Action Inc. used an electrician, [redacted] with For A Electric and he was a super gentleman. They selected McLeans Heating and A/C, owner [redacted], whose workers were [redacted] and [redacted]. They installed a new unit and duct work. I was very pleased with their work and kindness.

I wanted to express my gratitude and share the great blessing I received and felt you should be aware of this wonderful organization and the gracious grants offered by Coastal Community Action! I would be so happy if you could acknowledge my appreciation to each one that has made my life more comfortable and efficient. I want to thank Duke Energy for their assistance and the other donors at Coastal Community Action who made the grants possible.

Sincerely,

[redacted]

.cc Coastal Community Action, CEO Lynn Good (Duke Energy)

April 28, 2016

Blue Ridge Community Action Inc.
601 East Fifth Street Ste. 255
Charlotte NC 28202

To Whom It May Concern,

My name is [redacted]. I have been a life long resident of the Stanly County area. During this time I made choices in my life that did not reflected a thoughtful planned out success for my future. So I struggled financially. Unfortunately, I never qualified to receive any of the grant money that was allotted to Stanly County to help those who were in need of assistance.

During my life in Stanly County I was blessed to have a son with disabilities which required total care. This job was the love and joy of my life for twenty years. Within that time I was attending school to get a degree which would increase pay, so I can better provide for my children. I had to drop out of school and had to let go many jobs because of my responsibility at home. He passed in 2009, and life itself was a struggle. At one point of my I had no hope nor did it even matter whether I got it together or not. One day, God, just gave me a want- to- live spirit again. So I found jobs that lasted short term and applied for assistance many times. This was very embarrassing and degrading because the people made you feel you just wanted a hand-out. The workers made you feel like scum. After being rejected many times, you have a fear of even seeking help. When it was cold I would put cover up to block off rooms so we would stay in one area of the house, using a space heater. When it was too hot, we would visit someone or mess around in stores until it cool off to go home. I heard about you through a friend at the Community Action in Albemarle. At my wits end I fearfully applied at the Blue Ridge Community Action.

My vocabulary does not even extend far enough to express what my heart truly feels for the blessing you gave my daughter and I. For two years we have been without heat and air. As a single parent making minimum wage and not forty hours a week, I had to prioritize which bills got paid and I just couldn't seem to fit this in my budget during that time. Through Gods power we survived.

I truly thank God for this program, and especially to one of your workers [redacted]. The compassionate spirit and concern was of one I have never experienced. Never once did I feel as though I was being seconded guessed about any information, nor made me feel inferior concerning my needs. Out of all the rejections and mistreatments were worth the reward of compassion we received.

Our hats off to you guys and our hands up to God for his mighty acts he showed through you as workers. Continue to show his love and he will continue to bless this business and each one individually for what you do for others.

Thanks,

[redacted]

Team effort helps keep man in home

Tim Reaves
reporter@thefranklinpress.com

Kenneth Cruse stood proud on his porch on West Old Murphy Road on Thursday.

"You don't know how much I appreciate it, folks," he said to a group of people from the county who helped him stay in his home.

Cruse, 64, is the beneficiary of a number of emergency repairs, weatherization and energy efficiency upgrades to his 86-year-old home. Over the last two years, he's seen his house repainted, his roof replaced, electrical service upgraded and the installation of an HVAC system, water heater, oven and insulation.

Cruse said the equipment upgrades and weatherization improvements have cut his power bill is half.

"It's quieter, it's warmer, I enjoy it now," he said. "I don't have to sit around in a sweat suit."

Duke Energy contributed about $10,000 from its $20 million statewide Helping Home Fund fund for a new stove, the rails on the porch and various weatherization upgrades, said Lisa Parrish, government and community relations manager for the company. Other funding came from the North Carolina Housing Finance Agency. World Changers did much of the housework on Cruse's home, including the new porch.

"This is probably one of the best examples of a public-private partnership," said John Fay, housing director for Macon County Housing Department (MCHD). "It's really a melding of funds and effort by many different organizations. … It was really great, because we got to do so much here."

Cruse is the third generation of his family to own the house, and he's lived there for 32 years. But propane expenses and electrical inefficiencies were pushing him to the breaking point.

"The way the house was set up before the intervention, there was no way," he said. "It's the only way I could've stayed in it."

Cruse, who lives on Social Security Disability and Supplemental Security Income, said he had no insulation in his home and an old gas furnace that seemed ready to catch on fire.

"Over the years, things happened, things just deteriorated," he said.

He said a friend of his let him know about MCHD, so he filled out an application to see if he qualified for any of the funding. It's typical of most MCHD clients, Fay said. They usually hear about the agency and its programs from friends and family members or local medical or senior services. Then they come to the MCHD office on Old Murphy Road and fill out an application. Staff members look at a number of factors, including income level and problem severity to prioritize the work. MCHD has 250 homes that need some kind of repairs or weatherization upgrades

"We make that determination and match the work with the capabilities," Fay said. "And sometimes we don't have those. Sometimes we end up having to use, for instance, Habitat for Humanity, Macon Baptist Association, various people in the community that are volunteers."

The work on Cruse's home represents a broader philosophy that places value on letting seniors age in place, Fay said.

Press photo/Tim Reaves

Kenneth Cruse pulls a pan out of an oven, which he received as part of Duke Energy's Helping Home Fund.

"It's important for people to be able to be around the things that they have comfort with and to be able to feel at home and not have to worry about it falling in on them," he said.

MCHD is located at 1419 Old Murphy Road, Franklin. Housing help is available for those who qualify. For more information, call 828-369-2605.

I/A

Norlina, NC - Warren County

To whom this may concern,

I wanted to send this letter of appreciation to Franklin Vance Warren and all of the companies that contributed to helping us make our home energy efficient, as well as, safe and livable. For the 2 years that we have had our home, it did not have a heating source. We used kerosene to stay warm in the winter and it was awful. My four children and myself developed asthma and breathing issues that we never had prior to using kerosene. The smell of the kerosene was so strong sometimes that it made our eyes water. We couldn't afford to do anything else besides the kerosene at that time. We finally invested in propane as our heating source, but it didn't heat up the whole house, so we used electric heaters as well. I am so thankful and grateful for the FVW programs because with their help, we were able to qualify for a program that installed central heating and air in our home and a gas pump that has now been such a blessing. With all of the work that the electricians and heating and cooling guys did, we would've never been able to afford such quality work and installation of this system. Not only did they help us in regards to our new heating source, but they also installed more insulation, installed a carbon monoxide detector, installed new shower heads, fixed holes in our walls, sheet rocked around our windows all in effort to help save us from wasting money by making our home energy efficient. They did so much and worked hard to make sure it was done correctly and with love. I can't imagine how my children and I, health would be today,if FVW hadn't been there for us. The most frustrating thing as a parent, is to watch your kids get sick while trying to protect them from freezing to death. It was like torture, to know that you had to do what you had to do to keep us all warm, while sacrificing our extended health in the process. I had to give my children breathing treatments daily, they suffered from headaches, nausea, and low energy and I believe it was from that kerosene. But now, they don't complain about headaches, they haven't had any breathing treatments since, and they are full of healthy energy. We are all happier and warm throughout the entire house. I now have peace of mind and deep gratitude in my heart for the program that I believe saved my families life. Thank you again for all of your help and investments into making our living situation better. Miracles&Blessings.

With Love,

[redacted]

Exhibit JH-6

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 92

Docket No. E-2, Sub 1219

Date of Request: **January 28, 2020**
Date of Response: **February 10, 2020**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 92-4, was provided to me by the following individual(s): Teresa Reed, Rates & Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Senior Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 92
DEP Docket No. E-2, Sub 1219
Item No. 92-4

Request:

4. For each program identified in question 3 above, please provide:
a. The amount of ratepayer funds involved in providing and administering each program.
b. The amount of shareholder funds involved in providing and administering each program outside of ratepayer funds.
c. The total dollars spent for each program in 2018 and 2019.
d. The number of customers participating in each program for 2018 and 2019.

The Company's response should provide a comprehensive view of the activities, funding, and customer involvement associated with each program. If the information is not readily available or calculable, the Company's response should explain any proxy calculation each Company used to estimate the data being requested.

Response:

Energy Efficiency Programs:

Please see attachment PS DR 92-4 (EE).xlsx for specific information relating to DEC and DEP's income-qualified EE programs listed in the Company's response to PS DR 92-3(a). For detailed information regarding all of the Company's DSM/EE programs listed in PS DR 92-3(a), please see the Direct Testimony and Exhibits of Robert P. Evans in Docket Nos. E-7, Sub 1192 and E-2, Sub 1206.

PS DR 92-4 (EE).xlsx

Shareholder Programs:

Please see attachment PS DR 92-4 (Shareholder).docx for information relating to the programs listed in response to PS DR 92-3(d) and (e).

PS DR 92-4
(Shareholder).docx

The Company will supplement this response with information relating to the programs listed in PS DR 92-3(b) and (c) as soon as possible.

4. For each program identified in question 3 above, please provide:

    a. The amount of ratepayer funds involved in providing and administering each program.
    b. The amount of shareholder funds involved in providing and administering each program outside of ratepayer funds.
    c. The total dollars spent for each program in 2018 and 2019.
    d. The number of customers participating in each program for 2018 and 2019.

<u>Reponse: Shareholder Programs</u>

DEC Shareholder Program: Helping Home Fund

	2018	**2019**
B. Administration Cost	$ 248,248.10	No Available Funds
C. Total Dollars Spent	$ 1,434,715.56	No Available Funds
D. Number of Participants	642	No Available Funds

DEP Shareholder Program: Helping Home Fund

	2018	**2019**
B. Administration Cost	$ 132,108.66	$ 177,825.82
C. Total Dollars Spent	$ 644,381.20	$1,135,275.65
D. Number of Participants	377	358

DEC Shareholder Program: Share the Warmth

	2018	**2019**
B. Administration Cost	$18,300	$18,300
C. Total Dollars Spent	$908,300	$1,068,300
D. Number of Participants	6167	6148

DEP Shareholder Program: Energy Neighbor Fund

	2018	**2019**
B. Administration Cost	N/A	N/A
C. Total Dollars Spent	$494,000	$534,000
D. Number of Participants	3300	3100

DEC Shareholder Program: Rate Case Settlement Funds[1]

	2019
B. Administration Cost	$6,100
C. Total Dollars Spent	$4,006,100
D. Number of Participants	10,261

[1] One-time payment of rate case settelement funds to local agencies distributed September 1, 2018.

O'Donnell Proxy Group
DCF Summary

Company	Forecasted Annualized Dividend Yield			Value Line									Average Plowback Growth Rate [4]	CFRA 3 Year Projected EPS CAGR [5]	Schwab LT Growth Rate 3-5 Years EPS (AEE) [6]
				10 Year			5 Year			Forecasted					
	13-Wks [1]	4-Wks [2]	Current [3]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	Exhibit KWO-2		
American Elec Pwr	3.0%	3.4%	3.4%	3.0%	4.5%	4.0%	4.0%	5.5%	3.0%	5.0%	5.5%	4.5%	3.4%	6.0%	6.2%
ALLETE Inc	3.3%	4.0%	4.0%	2.5%	3.0%	5.0%	4.0%	3.5%	5.0%	5.5%	5.5%	4.5%	2.6%	10.0%	7.0%
Alliant Energy	2.8%	3.1%	3.0%	5.0%	7.0%	4.0%	5.0%	7.0%	5.0%	6.5%	5.5%	7.5%	4.0%	6.0%	5.7%
Ameren Corp	2.5%	2.8%	2.6%	1.0%	-2.0%	-0.5%	6.5%	3.0%	2.5%	6.0%	5.0%	6.0%	4.3%	6.0%	4.9%
CMS Energy Corp	2.6%	2.8%	2.7%	9.5%	15.0%	4.5%	7.0%	7.0%	5.5%	7.5%	7.0%	7.5%	5.2%	8.0%	7.5%
Consol. Edison	3.5%	3.8%	3.8%	2.5%	2.0%	5.0%	2.0%	2.5%	4.0%	3.0%	3.5%	3.5%	2.8%	4.0%	2.4%
Dominion Energy	4.6%	5.1%	4.9%	3.0%	7.5%	4.5%	3.5%	7.5%	6.5%	7.0%	4.5%	6.5%	2.7%	4.0%	4.9%
Duke Energy	4.2%	4.8%	4.6%	2.5%	7.0%	1.0%	0.5%	3.0%	1.5%	6.0%	2.5%	2.5%	1.7%	5.0%	4.1%
Edison International	3.9%	4.9%	4.6%	-3.5%	6.5%	3.0%	-9.0%	11.0%	3.0%	NMF	4.5%	5.5%	5.5%	NMF	3.2%
Entergy Corp	3.2%	3.9%	3.8%	-0.5%	2.5%	1.0%	0.5%	1.5%	-2.5%	3.0%	4.0%	5.0%	4.5%	6.0%	-1.5%
Eversource Energy	2.6%	2.9%	2.7%	8.0%	9.5%	6.5%	7.0%	8.0%	5.0%	5.5%	6.0%	5.0%	3.5%	6.0%	5.7%
Hawaiian Electric	2.9%	3.2%	3.0%	5.0%	-	3.0%	4.0%	-	3.5%	2.5%	3.0%	3.5%	2.8%	5.0%	3.3%
IDACORP Inc	2.7%	3.1%	3.0%	7.0%	6.5%	5.5%	4.0%	10.0%	5.0%	3.5%	7.0%	4.0%	4.1%	3.0%	2.5%
MGE Energy Inc	2.0%	2.2%	2.2%	4.5%	3.5%	5.5%	2.5%	4.0%	5.5%	5.5%	5.5%	5.0%	4.6%	4.8%	-
NextEra Energy	2.2%	2.5%	2.3%	6.0%	9.0%	8.5%	6.0%	10.5%	9.5%	10.0%	10.5%	7.0%	3.9%	8.0%	7.6%
Northwestern Corp	3.4%	3.9%	3.9%	8.5%	5.0%	5.5%	7.0%	7.0%	8.0%	2.0%	4.5%	3.5%	3.0%	4.0%	3.8%
OGE Energy Corp	4.2%	5.5%	5.1%	5.0%	7.0%	7.0%	2.0%	10.0%	5.5%	4.5%	6.0%	3.5%	3.5%	5.0%	2.9%
Otter Tail Corp	3.0%	3.5%	3.2%	5.5%	1.5%	-	9.0%	2.5%	4.5%	5.0%	5.0%	5.0%	3.8%	4.6%	-
Pinnacle West	3.6%	4.2%	4.1%	4.5%	2.5%	2.5%	5.0%	3.0%	4.5%	4.0%	6.0%	3.5%	3.5%	5.0%	4.6%
PNM Resources	2.6%	3.2%	3.1%	7.0%	2.5%	-	6.0%	11.0%	1.0%	7.0%	7.0%	5.0%	4.1%	6.0%	6.3%
Portland General	3.0%	3.5%	3.2%	3.5%	4.5%	2.5%	4.0%	4.5%	3.5%	4.5%	6.5%	3.0%	3.3%	5.0%	4.7%
Public Serv Enterprise Group	3.7%	4.5%	4.4%	1.5%	3.5%	6.5%	1.0%	4.0%	5.0%	6.0%	5.0%	5.0%	4.6%	4.0%	3.5%
Sempra Energy	3.1%	3.9%	3.5%	1.0%	10.0%	5.5%	2.0%	7.5%	4.0%	11.0%	8.0%	7.0%	3.9%	12.0%	-
Southern Co	4.1%	4.7%	4.4%	3.0%	3.5%	4.0%	2.5%	3.5%	3.0%	4.0%	3.0%	4.0%	3.1%	4.0%	2.1%
WEC Energy Group	2.7%	2.9%	2.8%	8.5%	14.5%	8.0%	6.0%	9.5%	10.5%	6.0%	6.5%	3.5%	3.8%	6.0%	6.2%
Xcel Energy	2.7%	3.0%	2.7%	5.5%	4.5%	4.5%	5.0%	6.0%	4.5%	5.5%	6.0%	5.5%	4.1%	6.0%	6.1%
AVERAGE	**3.2%**	**3.7%**	**3.5%**	**4.2%**	**5.6%**	**4.4%**	**3.7%**	**6.1%**	**4.5%**	**5.4%**	**5.5%**	**4.8%**	**3.7%**	**5.7%**	**4.5%**

Notes:

EPS = earnings per share
DPS = dividends per share
BPS = book value per share

Sources:

[1] The Value Line Investment Survey, Summary and Index: 1/17/2020 1/24/2020 1/31/2020 2/7/2020 2/14/2020 2/21/2020 2/28/2020 3/6/2020 3/13/2020
3/20/2020 3/27/2020 4/3/2020 4/10/2020
[2] The Value Line Investment Survey, Summary and Index: 3/20/2020 3/27/2020 4/3/2020 4/10/2020
[3] The Value Line Investment Survey, Summary and Index: 4/10/2020
[4] The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)
[5] CFRA Stock Report earnings estimates as of 3/13/2020 as provided by Schwab.com
[6] Schwab Equity Report earnings estimates as of 3/13/2020 as provided by Schwab.com

EXHIBIT KWO-1

O'Donnell Proxy Group
Plowback Ratios

Company	% Retained to Common Equity				
	2017	2018	2019 / 2019E*	2022E* - 2025E*	Average
American Elec Pwr	3.2%	3.5%	3.4%	3.5%	3.4%
ALLETE Inc	2.4%	2.7%	2.3%	3.0%	2.6%
Alliant Energy	4.0%	4.4%	4.2%	3.5%	4.0%
Ameren Corp	3.4%	4.8%	4.4%	4.5%	4.3%
CMS Energy Corp	5.2%	5.3%	4.9%	5.5%	5.2%
Consol. Edison	3.0%	3.5%	2.0%	2.5%	2.8%
Dominion Energy	1.8%	NMF	NMF	3.5%	2.7%
Duke Energy	1.2%	1.0%	2.0%	2.5%	1.7%
Edison International	6.6%	NMF	5.0%	5.0%	5.5%
Entergy Corp	3.9%	4.9%	5.2%	4.0%	4.5%
Eversource Energy	3.5%	3.4%	3.5%	3.5%	3.5%
Hawaiian Electric	2.1%	3.1%	3.0%	3.0%	2.8%
IDACORP Inc	4.4%	4.4%	4.0%	3.5%	4.1%
MGE Energy Inc	4.2%	4.7%	4.6%	5.0%	4.6%
NextEra Energy	4.4%	3.2%	3.5%	4.5%	3.9%
Northwestern Corp	3.4%	3.2%	3.0%	2.5%	3.0%
OGE Energy Corp	3.5%	3.8%	3.6%	3.0%	3.5%
Otter Tail Corp	3.3%	4.0%	4.0%	4.0%	3.8%
Pinnacle West	4.2%	3.9%	3.0%	3.0%	3.5%
PNM Resources	4.5%	2.9%	5.0%	4.0%	4.1%
Portland General	3.6%	3.5%	3.0%	3.0%	3.3%
Public Serv Enterprise Group	4.1%	3.4%	6.0%	5.0%	4.6%
Sempra Energy	3.3%	4.1%	3.0%	5.0%	3.9%
Southern Co	3.9%	2.6%	2.5%	3.5%	3.1%
WEC Energy Group	3.6%	3.7%	3.8%	4.0%	3.8%
Xcel Energy	3.9%	4.3%	4.0%	4.0%	4.1%
AVERAGE	**3.6%**	**3.7%**	**3.7%**	**3.8%**	**3.7%**

*E = expected
Plowback = Percent retained to common equity
The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

O'Donnell Proxy Group
Returns on Book Value

Company	% Return on Common Equity 2017	2018	2019 / 2019E*	2022E* - 2025E*
American Elec Pwr	9.8%	10.1%	10.3%	10.5%
ALLETE Inc	7.7%	8.1%	7.7%	8.5%
Alliant Energy	6.4%	11.2%	10.7%	10.5%
Ameren Corp	9.4%	10.7%	10.3%	10.0%
CMS Energy Corp	13.7%	13.8%	13.6%	13.5%
Consol. Edison	8.2%	8.5%	7.0%	8.5%
Dominion Energy	13.1%	10.6%	6.5%	13.5%
Duke Energy	7.1%	6.7%	8.0%	8.5%
Edison International	12.7%	NMF	11.5%	11.0%
Entergy Corp	11.7%	12.2%	12.1%	11.0%
Eversource Energy	8.9%	9.0%	9.0%	9.5%
Hawaiian Electric	8.5%	9.3%	9.5%	9.0%
IDACORP Inc	9.4%	9.6%	9.0%	9.5%
MGE Energy Inc	9.8%	10.3%	10.2%	10.5%
NextEra Energy	10.9%	9.4%	10.0%	13.0%
Northwestern Corp	9.0%	8.8%	9.0%	9.0%
OGE Energy Corp	10.0%	10.6%	10.9%	11.0%
Otter Tail Corp	10.6%	11.3%	11.1%	11.5%
Pinnacle West	9.9%	9.8%	9.5%	10.0%
PNM Resources	9.1%	7.9%	10.5%	9.0%
Portland General	8.4%	8.5%	8.5%	9.0%
Public Serv Enterprise Group	10.3%	9.7%	12.5%	11.0%
Sempra Energy	9.2%	10.0%	9.5%	11.5%
Southern Co	13.4%	12.5%	12.0%	13.0%
WEC Energy Group	10.5%	10.8%	11.2%	12.5%
Xcel Energy	10.2%	10.3%	10.5%	10.5%
AVERAGE	**9.9%**	**10.0%**	**10.0%**	**10.6%**

*E = expected

The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

O'Donnell Proxy Group

DCF Results & Recommendation

O'Donnell DCF Calculation

	13-Weeks a	4-Weeks b	1-Week c
	Exhibit KWO-1 →		
DIVIDEND YIELD AVERAGES	3.2%	3.7%	3.5%

Growth Rates	EPS d	DPS e	BPS f
	Exhibit KWO-1 →		
10-Year Growth Rate Averages	4.2%	5.6%	4.4%
5-Year Growth Rate Averages	3.7%	6.1%	4.5%
HISTORICAL GROWTH RATE AVERAGES	4.0%	5.9%	4.4%

	EPS g	DPS h	BPS i
	Exhibit KWO-1 →		
FORECASTED GROWTH RATE AVERAGES	5.4%	5.5%	4.8%

	13-Weeks EPS = a + d	13-Weeks DPS = a + e	13-Weeks BPS = a + f	4-Weeks EPS = b + d	4-Weeks DPS = b + e	4-Weeks BPS = b + f	1-Week EPS = c + d	1-Week DPS = c + e	1-Week BPS = c + f
	Rx →								
HISTORICAL GROWTH RATE AVERAGES + DIV YIELD AVERAGES	7.1%	9.0%	7.6%	7.6%	9.5%	8.1%	7.5%	9.4%	7.9%

	13-Weeks EPS = a + g	13-Weeks DPS = a + h	13-Weeks BPS = a + i	4-Weeks EPS = b + g	4-Weeks DPS = b + h	4-Weeks BPS = b + i	1-Week EPS = c + g	1-Week DPS = c + h	1-Week BPS = c + i
	Rx →								
FORECASTED GROWTH RATE AVERAGES + DIV YIELD AVERAGES	8.6%	8.7%	8.0%	9.1%	9.2%	8.5%	8.9%	9.0%	8.3%

O'Donnell Proxy Group
DCF Results & Recommendation

O'Donnell DCF Calculation (cont'd

	DIV YIELD AVERAGES			PLOWBACK	PLOWBACK + DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week				
	a	b	c	d	= a + d	= b + d	= c + d
	Exhibit KWO-1			Exhibit KWO-2	Rx		
American Elec Pwr	3.0%	3.4%	3.4%	3.4%	6.4%	6.8%	6.8%
ALLETE Inc	3.3%	4.0%	4.0%	2.6%	5.9%	6.6%	6.6%
Alliant Energy	2.8%	3.1%	3.0%	4.0%	6.8%	7.2%	7.0%
Ameren Corp	2.5%	2.8%	2.6%	4.3%	6.8%	7.0%	6.9%
CMS Energy Corp	2.6%	2.8%	2.7%	5.2%	7.8%	8.0%	7.9%
Consol. Edison	3.5%	3.8%	3.8%	2.8%	6.3%	6.6%	6.6%
Dominion Energy	4.6%	5.1%	4.9%	2.7%	7.3%	7.8%	7.6%
Duke Energy	4.2%	4.8%	4.6%	1.7%	5.9%	6.5%	6.3%
Edison International	3.9%	4.9%	4.6%	5.5%	9.4%	10.4%	10.1%
Entergy Corp	3.2%	3.9%	3.8%	4.5%	7.7%	8.4%	8.3%
Eversource Energy	2.6%	2.9%	2.7%	3.5%	6.1%	6.3%	6.2%
Hawaiian Electric	2.9%	3.2%	3.0%	2.8%	5.7%	6.0%	5.8%
IDACORP Inc	2.7%	3.1%	3.0%	4.1%	6.8%	7.2%	7.1%
MGE Energy Inc	2.0%	2.2%	2.2%	4.6%	6.6%	6.9%	6.8%
NextEra Energy	2.2%	2.5%	2.3%	3.9%	6.1%	6.4%	6.2%
Northwestern Corp	3.4%	3.9%	3.9%	3.0%	6.4%	7.0%	6.9%
OGE Energy Corp	4.2%	5.5%	5.1%	3.5%	7.6%	8.9%	8.6%
Otter Tail Corp	3.0%	3.5%	3.2%	3.8%	6.8%	7.4%	7.0%
Pinnacle West	3.6%	4.2%	4.1%	3.5%	7.1%	7.7%	7.6%
PNM Resources	2.6%	3.2%	3.1%	4.1%	6.7%	7.3%	7.2%
Portland General	3.0%	3.5%	3.2%	3.3%	6.3%	6.7%	6.5%
Public Serv Enterprise Group	3.7%	4.5%	4.4%	4.6%	8.3%	9.1%	9.0%
Sempra Energy	3.1%	3.9%	3.5%	3.9%	6.9%	7.7%	7.4%
Southern Co	4.1%	4.7%	4.4%	3.1%	7.2%	7.9%	7.5%
WEC Energy Group	2.7%	2.9%	2.8%	3.8%	6.4%	6.6%	6.6%
Xcel Energy	2.7%	3.0%	2.7%	4.1%	6.8%	7.1%	6.8%
AVERAGE	2.8%	3.1%	3.3%	3.7%	6.9%	7.4%	7.2%

O'Donnell Proxy Group

DCF Results & Recommendation

O'Donnell DCF Range	Low End Range	Average	High End Range
	7.00%	8.50%	10.00%

O'Donnell DCF Recommendation	8.75%

O'Donnell Proxy Group
CAPM Results

Comparable Group

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.55	4.0%	5.64%	
Treasury - Average	2.70%	0.55	4.0%	4.89%	
Treasury - Minimum	0.99%	0.55	4.0%	3.17%	LOW

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.55	6.0%	6.74%	HIGH
Treasury - Average	2.70%	0.55	6.0%	5.98%	
Treasury - Minimum	0.99%	0.55	6.0%	4.27%	

Source: *1. US Treasury Yields: February 23, 2018 through April 10, 2020*
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

I/A

Hevert Proxy Group
DCF Summary

Company	Forecasted Annualized Dividend Yield			Value Line 10 Year			Value Line 5 Year			Value Line Forecasted			Average Plowback Growth Rate [4]	CFRA 3 Year Projected EPS CAGR [5]	Schwab LT Growth Rate 3-5 Years EPS (AEE) [6]
	13-Wks [1]	4-Wks [2]	Current [3]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	Exhibit KWO-7		
American Elec Pwr	3.0%	3.4%	3.4%	3.0%	4.5%	4.0%	4.0%	5.5%	3.0%	5.0%	5.5%	4.5%	3.4%	6.0%	6.2%
ALLETE Inc	3.3%	4.0%	4.0%	2.5%	3.0%	5.0%	4.0%	3.5%	5.0%	5.5%	5.5%	4.5%	2.6%	10.0%	7.0%
Alliant Energy	2.8%	3.1%	3.0%	5.0%	7.0%	4.0%	5.0%	7.0%	5.0%	6.5%	5.5%	7.5%	4.0%	6.0%	5.7%
Ameren Corp	2.5%	2.8%	2.6%	1.0%	-2.0%	-0.5%	6.5%	3.0%	2.5%	6.0%	5.0%	6.0%	4.3%	6.0%	4.9%
Avangrid Inc	3.6%	4.0%	4.0%	-	-	-	-	-	-	8.5%	3.6%	1.5%	1.3%	8.0%	6.3%
CMS Energy Corp	2.6%	2.8%	2.7%	9.5%	15.0%	4.5%	7.0%	7.0%	5.5%	7.5%	7.0%	7.5%	5.2%	8.0%	7.5%
DTE Energy Co	3.6%	4.6%	4.2%	8.0%	5.5%	4.5%	7.5%	7.0%	5.0%	5.0%	6.5%	5.5%	4.4%	6.0%	6.0%
Evergy Inc.	3.2%	3.7%	3.5%	-	-	-	-	-	-	NMF	NMF	NMF	1.8%	8.0%	6.5%
Hawaiian Electric	2.9%	3.2%	3.0%	5.0%	-	3.0%	4.0%	-	3.5%	2.5%	3.0%	3.5%	2.8%	5.0%	3.3%
NextEra Energy	2.2%	2.5%	2.3%	6.0%	9.0%	8.5%	6.0%	10.5%	9.5%	10.0%	10.5%	7.0%	3.9%	8.0%	7.6%
Northwestern Corp	3.4%	3.9%	3.9%	8.5%	5.0%	5.5%	7.0%	7.0%	8.0%	2.0%	4.5%	3.5%	3.0%	4.0%	3.8%
OGE Energy Corp	4.2%	5.5%	5.1%	5.0%	7.0%	7.0%	2.0%	10.0%	5.5%	4.5%	6.0%	3.5%	3.5%	5.0%	2.9%
Otter Tail Corp	3.0%	3.5%	3.2%	5.5%	1.5%	-	9.0%	2.5%	4.5%	5.0%	5.0%	5.0%	3.8%	4.6%	-
Pinnacle West	3.6%	4.2%	4.1%	4.5%	2.5%	2.5%	5.0%	3.0%	4.5%	4.0%	6.0%	3.5%	3.5%	5.0%	4.6%
PNM Resources	2.6%	3.2%	3.1%	7.0%	2.5%	-	6.0%	11.0%	1.0%	7.0%	7.0%	5.0%	4.1%	6.0%	6.3%
Portland General	3.0%	3.5%	3.2%	3.5%	4.5%	2.5%	4.0%	4.5%	3.5%	4.5%	6.5%	3.0%	3.3%	5.0%	4.7%
Southern Co	4.1%	4.7%	4.4%	3.0%	3.5%	4.0%	2.5%	3.5%	3.0%	4.0%	3.0%	4.0%	3.1%	4.0%	2.1%
WEC Energy Group	2.7%	2.9%	2.8%	8.5%	14.5%	8.0%	6.0%	9.5%	10.5%	6.0%	6.5%	3.5%	3.8%	6.0%	6.2%
Xcel Energy	2.7%	3.0%	2.7%	5.5%	4.5%	4.5%	5.0%	6.0%	4.5%	5.5%	6.0%	5.5%	4.1%	6.0%	6.1%
AVERAGE	**3.1%**	**3.6%**	**3.4%**	**5.4%**	**5.5%**	**4.5%**	**5.3%**	**6.3%**	**4.9%**	**5.5%**	**5.7%**	**4.7%**	**3.5%**	**6.1%**	**5.4%**

Notes:
EPS = earnings per share
DPS = dividends per share
BPS = book value per share

Sources:

[1] The Value Line Investment Survey, Summary and Index: 1/17/2020 1/24/2020 1/31/2020 2/7/2020 2/14/2020 2/21/2020 2/28/2020 3/6/2020 3/13/2020 3/20/2020 3/27/2020 4/3/2020 4/10/2020
[2] The Value Line Investment Survey, Summary and Index: 3/20/2020 3/27/2020 4/3/2020 4/10/2020
[3] The Value Line Investment Survey, Summary and Index: 4/10/2020
[4] The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)
[5] CFRA Stock Report earnings estimates as of 3/13/2020 as provided by Schwab.com
[6] Schwab Equity Report earnings estimates as of 3/13/2020 as provided by Schwab.com

EXHIBIT KWO-6

Hevert Proxy Group
Plowback Ratios

Company	% Retained to Common Equity				
	2017 [1]	2018 [1]	2019 / 2019E* [1]	2022E* - 2025E* [1]	Average
American Elec Pwr	3.2%	3.5%	3.4%	3.5%	3.4%
ALLETE Inc	2.4%	2.7%	2.3%	3.0%	2.6%
Alliant Energy	4.0%	4.4%	4.2%	3.5%	4.0%
Ameren Corp	3.4%	4.8%	4.4%	4.5%	4.3%
Avangrid Inc	NMF	0.4%	1.5%	2.0%	1.3%
CMS Energy Corp	5.2%	5.3%	4.9%	5.5%	5.2%
DTE Energy Co	4.6%	4.9%	4.1%	4.0%	4.4%
Evergy Inc.	-	0.6%	2.4%	2.5%	1.8%
Hawaiian Electric	2.1%	3.1%	3.0%	3.0%	2.8%
NextEra Energy	4.4%	3.2%	3.5%	4.5%	3.9%
Northwestern Corp	3.4%	3.2%	3.0%	2.5%	3.0%
OGE Energy Corp	3.5%	3.8%	3.6%	3.0%	3.5%
Otter Tail Corp	3.3%	4.0%	4.0%	4.0%	3.8%
Pinnacle West	4.2%	3.9%	3.0%	3.0%	3.5%
PNM Resources	4.5%	2.9%	5.0%	4.0%	4.1%
Portland General	3.6%	3.5%	3.0%	3.0%	3.3%
Southern Co	3.9%	2.6%	2.5%	3.5%	3.1%
WEC Energy Group	3.6%	3.7%	3.8%	4.0%	3.8%
Xcel Energy	3.9%	4.3%	4.0%	4.0%	4.1%
AVERAGE	**3.7%**	**3.4%**	**3.5%**	**3.5%**	**3.5%**

*E = expected
Plowback = Percent retained to common equity
The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

Hevert Proxy Group
Returns on Book Value

	% Return on Common Equity			
Company	2017	2018	2019 / 2019E* [1]	2022E* - 2025E* [1]
American Electric Power Co Inc	9.8%	10.1%	10.3%	10.5%
ALLETE Inc	7.7%	8.1%	7.7%	8.5%
Alliant Energy Corp	6.4%	11.2%	10.7%	10.5%
Ameren Corp	9.4%	10.7%	10.3%	10.0%
Avangrid	3.4%	3.9%	5.0%	6.0%
CMS Energy Corp	13.7%	13.8%	13.6%	13.5%
DTE Energy Co	10.8%	10.9%	10.0%	10.5%
Evergy Corp.	-	5.3%	7.8%	8.5%
Hawaiian Electric Industries Inc	8.5%	9.3%	9.5%	9.0%
NextEra Energy Inc	10.9%	9.4%	10.0%	13.0%
Northwestern Corp	9.0%	8.8%	9.0%	9.0%
OGE Energy Corp	10.0%	10.6%	10.9%	11.0%
Otter Tail Corp	10.6%	11.3%	11.1%	11.5%
Pinnacle West Capital Corp	9.9%	9.8%	9.5%	10.0%
PNM Resources Inc	9.1%	7.9%	10.5%	9.0%
Portland General Electric Co	8.4%	8.5%	8.5%	9.0%
Southern Co (The)	13.4%	12.5%	12.0%	13.0%
WEC Energy Group Inc	10.5%	10.8%	11.2%	12.5%
Xcel Energy Inc	10.2%	10.3%	10.5%	10.5%
AVERAGE	**9.5%**	**9.6%**	**9.9%**	**10.3%**

*E = expected
The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

Hevert Proxy Group
DCF Results & Recommendation

Hevert DCF Calculation

	13-Weeks	4-Weeks	1-Week
	a	b	c
	Exhibit KWO-6 →		
DIVIDEND YIELD AVERAGES	3.1%	3.6%	3.4%

Growth Rates	EPS	DPS	BPS
	d	e	f
	Exhibit KWO-6 →		
10-Year Growth Rate Averages	5.4%	5.5%	4.5%
5-Year Growth Rate Averages	5.3%	6.3%	4.9%
HISTORICAL GROWTH RATE AVERAGES	5.3%	5.9%	4.7%

	EPS	DPS	BPS
	g	h	i
	Exhibit KWO-6 →		
FORECASTED GROWTH RATE AVERAGES	5.5%	5.7%	4.7%

	13-Weeks EPS	13-Weeks DPS	13-Weeks BPS	4-Weeks EPS	4-Weeks DPS	4-Weeks BPS	1-Week EPS	1-Week DPS	1-Week BPS
	= a + d	= a + e	= a + f	= b + d	= b + e	= b + f	= c + d	= c + e	= c + f
	Rx →								
HISTORICAL GROWTH RATE AVERAGES + DIV YIELD AVERAGES	8.4%	9.0%	7.8%	8.9%	9.5%	8.3%	8.8%	9.3%	8.1%

	13-Weeks EPS	13-Weeks DPS	13-Weeks BPS	4-Weeks EPS	4-Weeks DPS	4-Weeks BPS	1-Week EPS	1-Week DPS	1-Week BPS
	= a + g	= a + h	= a + i	= b + g	= b + h	= b + i	= c + g	= c + h	= c + i
	Rx →								
FORECASTED GROWTH RATE AVERAGES + DIV YIELD AVERAGES	8.6%	8.8%	7.8%	9.1%	9.3%	8.3%	8.9%	9.1%	8.1%

Hevert Proxy Group
DCF Results & Recommendation

Hevert DCF Calculation (cont'd)

	DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week
	a	b	c
	Exhibit KWO-6 →		
American Elec Pwr	3.0%	3.4%	3.4%
ALLETE Inc	3.3%	4.0%	4.0%
Alliant Energy	2.8%	3.1%	3.0%
Ameren Corp	2.5%	2.8%	2.6%
Avangrid Inc	3.6%	4.0%	4.0%
CMS Energy Corp	2.6%	2.8%	2.7%
DTE Energy Co	3.6%	4.6%	4.2%
Evergy Inc.	3.2%	3.7%	3.5%
Hawaiian Electric	2.9%	3.2%	3.0%
NextEra Energy	2.2%	2.5%	2.3%
Northwestern Corp	3.4%	3.9%	3.9%
OGE Energy Corp	4.2%	5.5%	5.1%
Otter Tail Corp	3.0%	3.5%	3.2%
Pinnacle West	3.6%	4.2%	4.1%
PNM Resources	2.6%	3.2%	3.1%
Portland General	3.0%	3.5%	3.2%
Southern Co	4.1%	4.7%	4.4%
WEC Energy Group	2.7%	2.9%	2.8%
Xcel Energy	2.7%	3.0%	2.7%
AVERAGE	**2.8%**	**3.1%**	**3.3%**

PLOWBACK	
	d
Exhibit KWO-7 →	
American Elec Pwr	3.4%
ALLETE Inc	2.6%
Alliant Energy	4.0%
Ameren Corp	4.3%
Avangrid Inc	1.3%
CMS Energy Corp	5.2%
DTE Energy Co	4.4%
Evergy Inc.	1.8%
Hawaiian Electric	2.8%
NextEra Energy	3.9%
Northwestern Corp	3.0%
OGE Energy Corp	3.5%
Otter Tail Corp	3.8%
Pinnacle West	3.5%
PNM Resources	4.1%
Portland General	3.3%
Southern Co	3.1%
WEC Energy Group	3.8%
Xcel Energy	4.1%
AVERAGE	**3.5%**

PLOWBACK + DIV YIELD AVERAGES		
= a + d	= b + d	= c + d
Rx →		
6.4%	6.8%	6.8%
5.9%	6.6%	6.6%
6.8%	7.2%	7.0%
6.8%	7.0%	6.9%
4.9%	5.3%	5.3%
7.8%	8.0%	7.9%
8.0%	9.0%	8.6%
5.0%	5.5%	5.3%
5.7%	6.0%	5.8%
6.1%	6.4%	6.2%
6.4%	7.0%	6.9%
7.6%	8.9%	8.6%
6.8%	7.4%	7.0%
7.1%	7.7%	7.6%
6.7%	7.3%	7.2%
6.3%	6.7%	6.5%
7.2%	7.9%	7.5%
6.4%	6.6%	6.6%
6.8%	7.1%	6.8%
6.6%	**7.1%**	**6.9%**

Hevert Proxy Group
DCF Results*

Hevert DCF Range Results	Mean Low	Mean	Mean High
30-Day Average	7.90%	8.78%	9.67%
90-Day Average	7.96%	8.84%	9.73%
180-Day Average	8.08%	8.97%	9.85%

*Witness Hevert Pre-Filed Testimony Pg. 84

Hevert Proxy Group
CAPM Results

Comparable Group

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.54	4.0%	5.62%	
Treasury - Average	2.71%	0.54	4.0%	4.86%	
Treasury - Minimum	0.99%	0.54	4.0%	3.15%	**LOW**

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.54	6.0%	6.69%	**HIGH**
Treasury - Average	2.71%	0.54	6.0%	5.94%	
Treasury - Minimum	0.99%	0.54	6.0%	4.22%	

Source: *1. US Treasury Yields: February 23, 2018 through April 7, 2020*
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

O'Donnell Proxy Group
DCF Summary

Company	Forecasted Annualized Dividend Yield			Value Line									Average Plowback Growth Rate [4]	CFRA 3 Year Projected EPS CAGR [5]	Schwab LT Growth Rate 3-5 Years EPS (AEE) [6]
				10 Year			5 Year			Forecasted					
	13-Wks [1]	4-Wks [2]	Current [3]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]			
													Exhibit KWO-2		
American Elec Pwr	3.0%	3.4%	3.4%	3.0%	4.5%	4.0%	4.0%	5.5%	3.0%	5.0%	5.5%	4.5%	3.4%	6.0%	6.2%
ALLETE Inc	3.3%	4.0%	4.0%	2.5%	3.0%	5.0%	4.0%	3.5%	5.0%	5.5%	5.5%	4.5%	2.6%	10.0%	7.0%
Alliant Energy	2.8%	3.1%	3.0%	5.0%	7.0%	4.0%	5.0%	7.0%	5.0%	6.5%	5.5%	7.5%	4.0%	6.0%	5.7%
Ameren Corp	2.5%	2.8%	2.6%	1.0%	-2.0%	-0.5%	6.5%	3.0%	2.5%	6.0%	5.0%	6.0%	4.3%	6.0%	4.9%
CMS Energy Corp	2.6%	2.8%	2.7%	9.5%	15.0%	4.5%	7.0%	7.0%	5.5%	7.5%	7.0%	7.5%	5.2%	8.0%	7.5%
Consol. Edison	3.5%	3.8%	3.8%	2.5%	2.0%	5.0%	2.0%	2.5%	4.0%	3.0%	3.5%	3.5%	2.8%	4.0%	2.4%
Dominion Energy	4.6%	5.1%	4.9%	3.0%	7.5%	4.5%	3.5%	7.5%	6.5%	7.0%	4.5%	6.5%	2.7%	4.0%	4.9%
Duke Energy	4.2%	4.8%	4.6%	2.5%	7.0%	1.0%	0.5%	3.0%	1.5%	6.0%	2.5%	2.5%	1.7%	5.0%	4.1%
Edison International	3.9%	4.9%	4.6%	-3.5%	6.5%	3.0%	-9.0%	11.0%	3.0%	NMF	4.5%	5.5%	5.5%	NMF	3.2%
Entergy Corp	3.2%	3.9%	3.8%	-0.5%	2.5%	1.0%	0.5%	1.5%	-2.5%	3.0%	4.0%	5.0%	4.5%	6.0%	-1.5%
Eversource Energy	2.6%	2.9%	2.7%	8.0%	9.5%	6.5%	7.0%	8.0%	5.0%	5.5%	6.0%	5.0%	3.5%	6.0%	5.7%
Hawaiian Electric	2.9%	3.2%	3.0%	5.0%	-	3.0%	4.0%	-	3.5%	2.5%	3.0%	3.5%	2.8%	5.0%	3.3%
IDACORP Inc	2.7%	3.1%	3.0%	7.0%	6.5%	5.5%	4.0%	10.0%	5.0%	3.5%	7.0%	4.0%	4.1%	3.0%	2.5%
MGE Energy Inc	2.0%	2.2%	2.2%	4.5%	3.5%	5.5%	2.5%	4.0%	5.5%	5.5%	5.5%	5.0%	4.6%	4.8%	-
NextEra Energy	2.2%	2.5%	2.3%	6.0%	9.0%	8.5%	6.0%	10.5%	9.5%	10.0%	10.5%	7.0%	3.9%	8.0%	7.6%
Northwestern Corp	3.4%	3.9%	3.9%	8.5%	5.0%	5.5%	7.0%	7.0%	8.0%	2.0%	4.5%	3.5%	3.0%	4.0%	3.8%
OGE Energy Corp	4.2%	5.5%	5.1%	5.0%	7.0%	7.0%	2.0%	10.0%	5.5%	4.5%	6.0%	3.5%	3.5%	5.0%	2.9%
Otter Tail Corp	3.0%	3.5%	3.2%	5.5%	1.5%	-	9.0%	2.5%	4.5%	5.0%	5.0%	5.0%	3.8%	4.6%	-
Pinnacle West	3.6%	4.2%	4.1%	4.5%	2.5%	2.5%	5.0%	3.0%	4.5%	4.0%	6.0%	3.5%	3.5%	5.0%	4.6%
PNM Resources	2.6%	3.2%	3.1%	7.0%	2.5%	-	6.0%	11.0%	1.0%	7.0%	7.0%	5.0%	4.1%	6.0%	6.3%
Portland General	3.0%	3.5%	3.2%	3.5%	4.5%	2.5%	4.0%	4.5%	3.5%	4.5%	6.5%	3.0%	3.3%	5.0%	4.7%
Public Serv Enterprise Group	3.7%	4.5%	4.4%	1.5%	3.5%	6.5%	1.0%	4.0%	5.0%	6.0%	5.0%	5.0%	4.6%	4.0%	3.5%
Sempra Energy	3.1%	3.9%	3.5%	1.0%	10.0%	5.5%	2.0%	7.5%	4.0%	11.0%	8.0%	7.0%	3.9%	12.0%	-
Southern Co	4.1%	4.7%	4.4%	3.0%	3.5%	4.0%	2.5%	3.5%	3.0%	4.0%	3.0%	4.0%	3.1%	4.0%	2.1%
WEC Energy Group	2.7%	2.9%	2.8%	8.5%	14.5%	8.0%	6.0%	9.5%	10.5%	6.0%	6.5%	3.5%	3.8%	6.0%	6.2%
Xcel Energy	2.7%	3.0%	2.7%	5.5%	4.5%	4.5%	5.0%	6.0%	4.5%	5.5%	6.0%	5.5%	4.1%	6.0%	6.1%
AVERAGE	**3.2%**	**3.7%**	**3.5%**	**4.2%**	**5.6%**	**4.4%**	**3.7%**	**6.1%**	**4.5%**	**5.4%**	**5.5%**	**4.8%**	**3.7%**	**5.7%**	**4.5%**

Notes:

EPS = earnings per share
DPS = dividends per share
BPS = book value per share

Sources:

[1]	The Value Line Investment Survey, Summary and Index:	1/17/2020	1/24/2020	1/31/2020	2/7/2020	2/14/2020	2/21/2020	2/28/2020	3/6/2020	3/13/2020
		3/20/2020	3/27/2020	4/3/2020	4/10/2020					
[2]	The Value Line Investment Survey, Summary and Index:	3/20/2020	3/27/2020	4/3/2020	4/10/2020					
[3]	The Value Line Investment Survey, Summary and Index:	4/10/2020								

[4] The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)
[5] CFRA Stock Report earnings estimates as of 3/13/2020 as provided by Schwab.com
[6] Schwab Equity Report earnings estimates as of 3/13/2020 as provided by Schwab.com

O'Donnell Proxy Group
Plowback Ratios

Company	% Retained to Common Equity 2017	2018	2019 / 2019E*	2022E* - 2025E*	Average
American Elec Pwr	3.2%	3.5%	3.4%	3.5%	3.4%
ALLETE Inc	2.4%	2.7%	2.3%	3.0%	2.6%
Alliant Energy	4.0%	4.4%	4.2%	3.5%	4.0%
Ameren Corp	3.4%	4.8%	4.4%	4.5%	4.3%
CMS Energy Corp	5.2%	5.3%	4.9%	5.5%	5.2%
Consol. Edison	3.0%	3.5%	2.0%	2.5%	2.8%
Dominion Energy	1.8%	NMF	NMF	3.5%	2.7%
Duke Energy	1.2%	1.0%	2.0%	2.5%	1.7%
Edison International	6.6%	NMF	5.0%	5.0%	5.5%
Entergy Corp	3.9%	4.9%	5.2%	4.0%	4.5%
Eversource Energy	3.5%	3.4%	3.5%	3.5%	3.5%
Hawaiian Electric	2.1%	3.1%	3.0%	3.0%	2.8%
IDACORP Inc	4.4%	4.4%	4.0%	3.5%	4.1%
MGE Energy Inc	4.2%	4.7%	4.6%	5.0%	4.6%
NextEra Energy	4.4%	3.2%	3.5%	4.5%	3.9%
Northwestern Corp	3.4%	3.2%	3.0%	2.5%	3.0%
OGE Energy Corp	3.5%	3.8%	3.6%	3.0%	3.5%
Otter Tail Corp	3.3%	4.0%	4.0%	4.0%	3.8%
Pinnacle West	4.2%	3.9%	3.0%	3.0%	3.5%
PNM Resources	4.5%	2.9%	5.0%	4.0%	4.1%
Portland General	3.6%	3.5%	3.0%	3.0%	3.3%
Public Serv Enterprise Group	4.1%	3.4%	6.0%	5.0%	4.6%
Sempra Energy	3.3%	4.1%	3.0%	5.0%	3.9%
Southern Co	3.9%	2.6%	2.5%	3.5%	3.1%
WEC Energy Group	3.6%	3.7%	3.8%	4.0%	3.8%
Xcel Energy	3.9%	4.3%	4.0%	4.0%	4.1%
AVERAGE	**3.6%**	**3.7%**	**3.7%**	**3.8%**	**3.7%**

*E = expected
Plowback = Percent retained to common equity
The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

O'Donnell Proxy Group
Returns on Book Value

	% Return on Common Equity			
Company	2017	2018	2019 / 2019E*	2022E* - 2025E*
American Elec Pwr	9.8%	10.1%	10.3%	10.5%
ALLETE Inc	7.7%	8.1%	7.7%	8.5%
Alliant Energy	6.4%	11.2%	10.7%	10.5%
Ameren Corp	9.4%	10.7%	10.3%	10.0%
CMS Energy Corp	13.7%	13.8%	13.6%	13.5%
Consol. Edison	8.2%	8.5%	7.0%	8.5%
Dominion Energy	13.1%	10.6%	6.5%	13.5%
Duke Energy	7.1%	6.7%	8.0%	8.5%
Edison International	12.7%	NMF	11.5%	11.0%
Entergy Corp	11.7%	12.2%	12.1%	11.0%
Eversource Energy	8.9%	9.0%	9.0%	9.5%
Hawaiian Electric	8.5%	9.3%	9.5%	9.0%
IDACORP Inc	9.4%	9.6%	9.0%	9.5%
MGE Energy Inc	9.8%	10.3%	10.2%	10.5%
NextEra Energy	10.9%	9.4%	10.0%	13.0%
Northwestern Corp	9.0%	8.8%	9.0%	9.0%
OGE Energy Corp	10.0%	10.6%	10.9%	11.0%
Otter Tail Corp	10.6%	11.3%	11.1%	11.5%
Pinnacle West	9.9%	9.8%	9.5%	10.0%
PNM Resources	9.1%	7.9%	10.5%	9.0%
Portland General	8.4%	8.5%	8.5%	9.0%
Public Serv Enterprise Group	10.3%	9.7%	12.5%	11.0%
Sempra Energy	9.2%	10.0%	9.5%	11.5%
Southern Co	13.4%	12.5%	12.0%	13.0%
WEC Energy Group	10.5%	10.8%	11.2%	12.5%
Xcel Energy	10.2%	10.3%	10.5%	10.5%
AVERAGE	**9.9%**	**10.0%**	**10.0%**	**10.6%**

*E = expected

The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

O'Donnell Proxy Group
DCF Results & Recommendation

O'Donnell DCF Calculation

	13-Weeks a	4-Weeks b	1-Week c
	Exhibit KWO-1		
DIVIDEND YIELD AVERAGES	3.2%	3.7%	3.5%

Growth Rates	EPS d	DPS e	BPS f
	Exhibit KWO-1		
10-Year Growth Rate Averages	4.2%	5.6%	4.4%
5-Year Growth Rate Averages	3.7%	6.1%	4.5%
HISTORICAL GROWTH RATE AVERAGES	4.0%	5.9%	4.4%

	EPS g	DPS h	BPS i
	Exhibit KWO-1		
FORECASTED GROWTH RATE AVERAGES	5.4%	5.5%	4.8%

	13-Weeks EPS = a + d	13-Weeks DPS = a + e	13-Weeks BPS = a + f	4-Weeks EPS = b + d	4-Weeks DPS = b + e	4-Weeks BPS = b + f	1-Week EPS = c + d	1-Week DPS = c + e	1-Week BPS = c + f
	Rx								
HISTORICAL GROWTH RATE AVERAGES + DIV YIELD AVERAGES	7.1%	9.0%	7.6%	7.6%	9.5%	8.1%	7.5%	9.4%	7.9%

	13-Weeks EPS = a + g	13-Weeks DPS = a + h	13-Weeks BPS = a + i	4-Weeks EPS = b + g	4-Weeks DPS = b + h	4-Weeks BPS = b + i	1-Week EPS = c + g	1-Week DPS = c + h	1-Week BPS = c + i
	Rx								
FORECASTED GROWTH RATE AVERAGES + DIV YIELD AVERAGES	8.6%	8.7%	8.0%	9.1%	9.2%	8.5%	8.9%	9.0%	8.3%

O'Donnell Proxy Group

DCF Results & Recommendation

O'Donnell DCF Calculation (cont'd

DIV YIELD AVERAGES	13-Weeks a	4-Weeks b	1-Week c
	Exhibit KWO-1 →		
American Elec Pwr	3.0%	3.4%	3.4%
ALLETE Inc	3.3%	4.0%	4.0%
Alliant Energy	2.8%	3.1%	3.0%
Ameren Corp	2.5%	2.8%	2.6%
CMS Energy Corp	2.6%	2.8%	2.7%
Consol. Edison	3.5%	3.8%	3.8%
Dominion Energy	4.6%	5.1%	4.9%
Duke Energy	4.2%	4.8%	4.6%
Edison International	3.9%	4.9%	4.6%
Entergy Corp	3.2%	3.9%	3.8%
Eversource Energy	2.6%	2.9%	2.7%
Hawaiian Electric	2.9%	3.2%	3.0%
IDACORP Inc	2.7%	3.1%	3.0%
MGE Energy Inc	2.0%	2.2%	2.2%
NextEra Energy	2.2%	2.5%	2.3%
Northwestern Corp	3.4%	3.9%	3.9%
OGE Energy Corp	4.2%	5.5%	5.1%
Otter Tail Corp	3.0%	3.5%	3.2%
Pinnacle West	3.6%	4.2%	4.1%
PNM Resources	2.6%	3.2%	3.1%
Portland General	3.0%	3.5%	3.2%
Public Serv Enterprise Group	3.7%	4.5%	4.4%
Sempra Energy	3.1%	3.9%	3.5%
Southern Co	4.1%	4.7%	4.4%
WEC Energy Group	2.7%	2.9%	2.8%
Xcel Energy	2.7%	3.0%	2.7%
AVERAGE	**2.8%**	**3.1%**	**3.3%**

PLOWBACK	d
Exhibit KWO-2 →	
American Elec Pwr	3.4%
ALLETE Inc	2.6%
Alliant Energy	4.0%
Ameren Corp	4.3%
CMS Energy Corp	5.2%
Consol. Edison	2.8%
Dominion Energy	2.7%
Duke Energy	1.7%
Edison International	5.5%
Entergy Corp	4.5%
Eversource Energy	3.5%
Hawaiian Electric	2.8%
IDACORP Inc	4.1%
MGE Energy Inc	4.6%
NextEra Energy	3.9%
Northwestern Corp	3.0%
OGE Energy Corp	3.5%
Otter Tail Corp	3.8%
Pinnacle West	3.5%
PNM Resources	4.1%
Portland General	3.3%
Public Serv Enterprise Group	4.6%
Sempra Energy	3.9%
Southern Co	3.1%
WEC Energy Group	3.8%
Xcel Energy	4.1%
AVERAGE	**3.7%**

PLOWBACK + DIV YIELD AVERAGES = a + d	= b + d	= c + d
Rx →		
6.4%	6.8%	6.8%
5.9%	6.6%	6.6%
6.8%	7.2%	7.0%
6.8%	7.0%	6.9%
7.8%	8.0%	7.9%
6.3%	6.6%	6.6%
7.3%	7.8%	7.6%
5.9%	6.5%	6.3%
9.4%	10.4%	10.1%
7.7%	8.4%	8.3%
6.1%	6.3%	6.2%
5.7%	6.0%	5.8%
6.8%	7.2%	7.1%
6.6%	6.9%	6.8%
6.1%	6.4%	6.2%
6.4%	7.0%	6.9%
7.6%	8.9%	8.6%
6.8%	7.4%	7.0%
7.1%	7.7%	7.6%
6.7%	7.3%	7.2%
6.3%	6.7%	6.5%
8.3%	9.1%	9.0%
6.9%	7.7%	7.4%
7.2%	7.9%	7.5%
6.4%	6.6%	6.6%
6.8%	7.1%	6.8%
6.9%	**7.4%**	**7.2%**

O'Donnell Proxy Group
DCF Results & Recommendation

O'Donnell DCF Range	Low End Range	Average	High End Range
	7.00%	8.50%	10.00%

O'Donnell DCF Recommendation	8.75%

O'Donnell Proxy Group
CAPM Results

Comparable Group

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.55	4.0%	5.64%	
Treasury - Average	2.70%	0.55	4.0%	4.89%	
Treasury - Minimum	0.99%	0.55	4.0%	3.17%	LOW

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.55	6.0%	6.74%	HIGH
Treasury - Average	2.70%	0.55	6.0%	5.98%	
Treasury - Minimum	0.99%	0.55	6.0%	4.27%	

Source: *1. US Treasury Yields: February 23, 2018 through April 10, 2020*
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Hevert Proxy Group
DCF Summary

Company	Forecasted Annualized Dividend Yield			Value Line									Average Plowback Growth Rate [4]	CFRA 3 Year Projected EPS CAGR [5]	Schwab LT Growth Rate 3-5 Years EPS (AEE) [6]
				10 Year			5 Year			Forecasted					
	13-Wks [1]	4-Wks [2]	Current [3]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]			
													Exhibit KWO-7		
American Elec Pwr	3.0%	3.4%	3.4%	3.0%	4.5%	4.0%	4.0%	5.5%	3.0%	5.0%	5.5%	4.5%	3.4%	6.0%	6.2%
ALLETE Inc	3.3%	4.0%	4.0%	2.5%	3.0%	5.0%	4.0%	3.5%	5.0%	5.5%	5.5%	4.5%	2.6%	10.0%	7.0%
Alliant Energy	2.8%	3.1%	3.0%	5.0%	7.0%	4.0%	5.0%	7.0%	5.0%	6.5%	5.5%	7.5%	4.0%	6.0%	5.7%
Ameren Corp	2.5%	2.8%	2.6%	1.0%	-2.0%	-0.5%	6.5%	3.0%	2.5%	6.0%	5.0%	6.0%	4.3%	6.0%	4.9%
Avangrid Inc	3.6%	4.0%	4.0%	-	-	-	-	-	-	8.5%	3.6%	1.5%	1.3%	8.0%	6.3%
CMS Energy Corp	2.6%	2.8%	2.7%	9.5%	15.0%	4.5%	7.0%	7.0%	5.5%	7.5%	7.0%	7.5%	5.2%	8.0%	7.5%
DTE Energy Co	3.6%	4.6%	4.2%	8.0%	5.5%	4.5%	7.5%	7.0%	5.0%	5.0%	6.5%	5.5%	4.4%	6.0%	6.0%
Evergy Inc.	3.2%	3.7%	3.5%	-	-	-	-	-	-	NMF	NMF	NMF	1.8%	8.0%	6.5%
Hawaiian Electric	2.9%	3.2%	3.0%	5.0%	-	3.0%	4.0%	-	3.5%	2.5%	3.0%	3.5%	2.8%	5.0%	3.3%
NextEra Energy	2.2%	2.5%	2.3%	6.0%	9.0%	8.5%	6.0%	10.5%	9.5%	10.0%	10.5%	7.0%	3.9%	8.0%	7.6%
Northwestern Corp	3.4%	3.9%	3.9%	8.5%	5.0%	5.5%	7.0%	7.0%	8.0%	2.0%	4.5%	3.5%	3.0%	4.0%	3.8%
OGE Energy Corp	4.2%	5.5%	5.1%	5.0%	7.0%	7.0%	2.0%	10.0%	5.5%	4.5%	6.0%	3.5%	3.5%	5.0%	2.9%
Otter Tail Corp	3.0%	3.5%	3.2%	5.5%	1.5%	-	9.0%	2.5%	4.5%	5.0%	5.0%	5.0%	3.8%	4.6%	-
Pinnacle West	3.6%	4.2%	4.1%	4.5%	2.5%	2.5%	5.0%	3.0%	4.5%	4.0%	6.0%	3.5%	3.5%	5.0%	4.6%
PNM Resources	2.6%	3.2%	3.1%	7.0%	2.5%	-	6.0%	11.0%	1.0%	7.0%	7.0%	5.0%	4.1%	6.0%	6.3%
Portland General	3.0%	3.5%	3.2%	3.5%	4.5%	2.5%	4.0%	4.5%	3.5%	4.5%	6.5%	3.0%	3.3%	5.0%	4.7%
Southern Co	4.1%	4.7%	4.4%	3.0%	3.5%	4.0%	2.5%	3.5%	3.0%	4.0%	3.0%	4.0%	3.1%	4.0%	2.1%
WEC Energy Group	2.7%	2.9%	2.8%	8.5%	14.5%	8.0%	6.0%	9.5%	10.5%	6.0%	6.5%	3.5%	3.8%	6.0%	6.2%
Xcel Energy	2.7%	3.0%	2.7%	5.5%	4.5%	4.5%	5.0%	6.0%	4.5%	5.5%	6.0%	5.5%	4.1%	6.0%	6.1%
AVERAGE	**3.1%**	**3.6%**	**3.4%**	**5.4%**	**5.5%**	**4.5%**	**5.3%**	**6.3%**	**4.9%**	**5.5%**	**5.7%**	**4.7%**	**3.5%**	**6.1%**	**5.4%**

Notes:

EPS = earnings per share
DPS = dividends per share
BPS = book value per share

Sources:

[1] The Value Line Investment Survey, Summary and Index: 1/17/2020 1/24/2020 1/31/2020 2/7/2020 2/14/2020 2/21/2020 2/28/2020 3/6/2020 3/13/2020 3/20/2020 3/27/2020 4/3/2020 4/10/2020
[2] The Value Line Investment Survey, Summary and Index: 3/20/2020 3/27/2020 4/3/2020 4/10/2020
[3] The Value Line Investment Survey, Summary and Index: 4/10/2020
[4] The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)
[5] CFRA Stock Report earnings estimates as of 3/13/2020 as provided by Schwab.com
[6] Schwab Equity Report earnings estimates as of 3/13/2020 as provided by Schwab.com

Hevert Proxy Group
Plowback Ratios

Company	% Retained to Common Equity				
	2017 [1]	2018 [1]	2019 / 2019E* [1]	2022E* - 2025E* [1]	Average
American Elec Pwr	3.2%	3.5%	3.4%	3.5%	3.4%
ALLETE Inc	2.4%	2.7%	2.3%	3.0%	2.6%
Alliant Energy	4.0%	4.4%	4.2%	3.5%	4.0%
Ameren Corp	3.4%	4.8%	4.4%	4.5%	4.3%
Avangrid Inc	NMF	0.4%	1.5%	2.0%	1.3%
CMS Energy Corp	5.2%	5.3%	4.9%	5.5%	5.2%
DTE Energy Co	4.6%	4.9%	4.1%	4.0%	4.4%
Evergy Inc.	-	0.6%	2.4%	2.5%	1.8%
Hawaiian Electric	2.1%	3.1%	3.0%	3.0%	2.8%
NextEra Energy	4.4%	3.2%	3.5%	4.5%	3.9%
Northwestern Corp	3.4%	3.2%	3.0%	2.5%	3.0%
OGE Energy Corp	3.5%	3.8%	3.6%	3.0%	3.5%
Otter Tail Corp	3.3%	4.0%	4.0%	4.0%	3.8%
Pinnacle West	4.2%	3.9%	3.0%	3.0%	3.5%
PNM Resources	4.5%	2.9%	5.0%	4.0%	4.1%
Portland General	3.6%	3.5%	3.0%	3.0%	3.3%
Southern Co	3.9%	2.6%	2.5%	3.5%	3.1%
WEC Energy Group	3.6%	3.7%	3.8%	4.0%	3.8%
Xcel Energy	3.9%	4.3%	4.0%	4.0%	4.1%
AVERAGE	**3.7%**	**3.4%**	**3.5%**	**3.5%**	**3.5%**

*E = expected
Plowback = Percent retained to common equity
The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

Hevert Proxy Group
Returns on Book Value

Company	% Return on Common Equity 2017	2018	2019 / 2019E* [1]	2022E* - 2025E* [1]
American Electric Power Co Inc	9.8%	10.1%	10.3%	10.5%
ALLETE Inc	7.7%	8.1%	7.7%	8.5%
Alliant Energy Corp	6.4%	11.2%	10.7%	10.5%
Ameren Corp	9.4%	10.7%	10.3%	10.0%
Avangrid	3.4%	3.9%	5.0%	6.0%
CMS Energy Corp	13.7%	13.8%	13.6%	13.5%
DTE Energy Co	10.8%	10.9%	10.0%	10.5%
Evergy Corp.	-	5.3%	7.8%	8.5%
Hawaiian Electric Industries Inc	8.5%	9.3%	9.5%	9.0%
NextEra Energy Inc	10.9%	9.4%	10.0%	13.0%
Northwestern Corp	9.0%	8.8%	9.0%	9.0%
OGE Energy Corp	10.0%	10.6%	10.9%	11.0%
Otter Tail Corp	10.6%	11.3%	11.1%	11.5%
Pinnacle West Capital Corp	9.9%	9.8%	9.5%	10.0%
PNM Resources Inc	9.1%	7.9%	10.5%	9.0%
Portland General Electric Co	8.4%	8.5%	8.5%	9.0%
Southern Co (The)	13.4%	12.5%	12.0%	13.0%
WEC Energy Group Inc	10.5%	10.8%	11.2%	12.5%
Xcel Energy Inc	10.2%	10.3%	10.5%	10.5%
AVERAGE	**9.5%**	**9.6%**	**9.9%**	**10.3%**

*E = expected

The Value Line Investment Survey: 1/24/2020 (Electric Utilities West), 2/14/2020 (Electric Utilities East), 3/13/2020 (Electric Utilities Central)

I/A

Hevert Proxy Group

DCF Results & Recommendation

Hevert DCF Calculation

	13-Weeks	4-Weeks	1-Week
	a	b	c
	Exhibit KWO-6 →		
DIVIDEND YIELD AVERAGES	3.1%	3.6%	3.4%

Growth Rates	EPS	DPS	BPS
	d	e	f
	Exhibit KWO-6 →		
10-Year Growth Rate Averages	5.4%	5.5%	4.5%
5-Year Growth Rate Averages	5.3%	6.3%	4.9%
HISTORICAL GROWTH RATE AVERAGES	5.3%	5.9%	4.7%

	EPS	DPS	BPS
	g	h	i
	Exhibit KWO-6 →		
FORECASTED GROWTH RATE AVERAGES	5.5%	5.7%	4.7%

	13-Weeks EPS	13-Weeks DPS	13-Weeks BPS	4-Weeks EPS	4-Weeks DPS	4-Weeks BPS	1-Week EPS	1-Week DPS	1-Week BPS
	= a + d	= a + e	= a + f	= b + d	= b + e	= b + f	= c + d	= c + e	= c + f
	Rx →								
HISTORICAL GROWTH RATE AVERAGES + DIV YIELD AVERAGES	8.4%	9.0%	7.8%	8.9%	9.5%	8.3%	8.8%	9.3%	8.1%

	13-Weeks EPS	13-Weeks DPS	13-Weeks BPS	4-Weeks EPS	4-Weeks DPS	4-Weeks BPS	1-Week EPS	1-Week DPS	1-Week BPS
	= a + g	= a + h	= a + i	= b + g	= b + h	= b + i	= c + g	= c + h	= c + i
	Rx →								
FORECASTED GROWTH RATE AVERAGES + DIV YIELD AVERAGES	8.6%	8.8%	7.8%	9.1%	9.3%	8.3%	8.9%	9.1%	8.1%

Hevert Proxy Group

DCF Results & Recommendation

Hevert DCF Calculation (cont'd)

	DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week
	a	b	c
	Exhibit KWO-6 →		
American Elec Pwr	3.0%	3.4%	3.4%
ALLETE Inc	3.3%	4.0%	4.0%
Alliant Energy	2.8%	3.1%	3.0%
Ameren Corp	2.5%	2.8%	2.6%
Avangrid Inc	3.6%	4.0%	4.0%
CMS Energy Corp	2.6%	2.8%	2.7%
DTE Energy Co	3.6%	4.6%	4.2%
Evergy Inc.	3.2%	3.7%	3.5%
Hawaiian Electric	2.9%	3.2%	3.0%
NextEra Energy	2.2%	2.5%	2.3%
Northwestern Corp	3.4%	3.9%	3.9%
OGE Energy Corp	4.2%	5.5%	5.1%
Otter Tail Corp	3.0%	3.5%	3.2%
Pinnacle West	3.6%	4.2%	4.1%
PNM Resources	2.6%	3.2%	3.1%
Portland General	3.0%	3.5%	3.2%
Southern Co	4.1%	4.7%	4.4%
WEC Energy Group	2.7%	2.9%	2.8%
Xcel Energy	2.7%	3.0%	2.7%
AVERAGE	**2.8%**	**3.1%**	**3.3%**

PLOWBACK	
	d
Exhibit KWO-7 →	
American Elec Pwr	3.4%
ALLETE Inc	2.6%
Alliant Energy	4.0%
Ameren Corp	4.3%
Avangrid Inc	1.3%
CMS Energy Corp	5.2%
DTE Energy Co	4.4%
Evergy Inc.	1.8%
Hawaiian Electric	2.8%
NextEra Energy	3.9%
Northwestern Corp	3.0%
OGE Energy Corp	3.5%
Otter Tail Corp	3.8%
Pinnacle West	3.5%
PNM Resources	4.1%
Portland General	3.3%
Southern Co	3.1%
WEC Energy Group	3.8%
Xcel Energy	4.1%
AVERAGE	**3.5%**

PLOWBACK + DIV YIELD AVERAGES		
= a + d	= b + d	= c + d
Rx →		
6.4%	6.8%	6.8%
5.9%	6.6%	6.6%
6.8%	7.2%	7.0%
6.8%	7.0%	6.9%
4.9%	5.3%	5.3%
7.8%	8.0%	7.9%
8.0%	9.0%	8.6%
5.0%	5.5%	5.3%
5.7%	6.0%	5.8%
6.1%	6.4%	6.2%
6.4%	7.0%	6.9%
7.6%	8.9%	8.6%
6.8%	7.4%	7.0%
7.1%	7.7%	7.6%
6.7%	7.3%	7.2%
6.3%	6.7%	6.5%
7.2%	7.9%	7.5%
6.4%	6.6%	6.6%
6.8%	7.1%	6.8%
6.6%	**7.1%**	**6.9%**

Hevert Proxy Group
DCF Results*

Hevert DCF Range Results	Mean Low	Mean	Mean High
30-Day Average	7.90%	8.78%	9.67%
90-Day Average	7.96%	8.84%	9.73%
180-Day Average	8.08%	8.97%	9.85%

*Witness Hevert Pre-Filed Testimony Pg. 84

Hevert Proxy Group
CAPM Results

Comparable Group

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.54	4.0%	5.62%	
Treasury - Average	2.71%	0.54	4.0%	4.86%	
Treasury - Minimum	0.99%	0.54	4.0%	3.15%	**LOW**

	30-Yr.Risk-Free Rate [1]	Average Proxy Group Beta	Equity Risk Premium	Equity Cost Rate	
Treasury - Maximum	3.46%	0.54	6.0%	6.69%	**HIGH**
Treasury - Average	2.71%	0.54	6.0%	5.94%	
Treasury - Minimum	0.99%	0.54	6.0%	4.22%	

Source: *1. US Treasury Yields: February 23, 2018 through April 7, 2020*
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Qualifications of

JONATHAN F. WALLACH

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SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

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"Economic Benefits from Early Retirement of Reid Gardner" (with Paul Chernick) prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

"Green Resource Portfolios: Development, Integration, and Evaluation" (with Paul Chernick and Richard Mazzini) report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

"Integrated Portfolio Management in a Restructured Supply Market" (with Paul Chernick, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"First Year of SOS Procurement." 2004. Prepared for the Maryland Office of People's Counsel.

“Energy Plan for the City of New York” (with Paul Chernick, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

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“Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets” (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People’s Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People’s Counsel of the District of Columbia.

“Comments Regarding Retail Electricity Competition.” 2001. Filed by the Maryland Office of People’s Counsel in U.S. FTC Docket No. V010003.

“Final Comments of the City of New York on Con Edison’s Generation Divestiture Plans and Petition.” 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

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"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Paul Chernick). 1996. Concord, N.H.: NH OCA.

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"Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities" (with Ken Keating et al.) 1992.

“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992. Report to the New Jersey Department of Public Advocate.

“Review of Rockland Electric Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992.

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“Comments on the Utility Responses to Commission’s November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans” (with John Plunkett et al.). 1991.

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“Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.” 1984. ESRG Study No. 83-81.

“Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission.” 1984. ESRG Study No. 83-51.

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"The Economics of Alternative Space and Water Heating Systems in New Construction in the Jersey Central Power and Light Service Area, A Report to the Public Advocate." 1982. ESRG Study No. 82-31.

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"Utility Promotion of Residential Customer Conservation, A Report to Massachusetts Public Interest Research Group." 1981. ESRG Study No. 81-47

PRESENTATIONS

"Office of People's Counsel Case No. 9117" (with William Fields). Presentation to the Maryland Public Utilities Commission in Case No. 9117, December 2008.

"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

Vt. PSB on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

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Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

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Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **Maryland PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

Maryland PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

Maryland PSC Case No. 9064, default service for residential and small commercial customers; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rate-stabilization and market-transition plan for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Rate-stabilization plan.

Maryland PSC Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rate-stabilization plan for Baltimore Gas & Electric; Maryland Office of People's Counsel, Direct, March 2007; Surrebuttal April 2007.

Review of standard-offer-service-procurement plan. Rate stabilization plan.

Connecticut DPUC Docket No. 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts.

Maryland PSC Case No. 9117, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct and Reply, September 2007; Supplemental Reply, November 2007; Additional Reply, December 2007; presentation, December 2008.

Benefits of long-term planning and procurement. Proposed aggregation of customers.

Maryland PSC Case No. 9117, Phase II, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct, October 2007.

Energy efficiency as part of standard-offer-service planning and procurement. Procurement of generation or long-term contracts to meet reliability needs.

2008 **Connecticut DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Paul Chernick), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Paul Chernick and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

2009 **Maryland PSC** Case No. 9192, Delmarva Power & Lights rates; Maryland Office of People's Counsel. Direct, August 2009; Rebuttal, Surrebuttal, September 2009.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6630-CE-302, Glacier Hills Wind Park certificate; Citizens Utility Board of Wisconsin. Direct and Surrebuttal, October 2009.

Reasonableness of proposed wind facility.

PUC of Ohio Case No 09-906-EL-SSO, standard-service-offer bidding for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, December 2009.

Design of auctions for SSO power supply. Implications of migration of First-Energy from MISO to PJM.

2010 **PUC of Ohio** Case No 10-388-EL-SSO, standard-service offer for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, July 2010.

Design of auctions for SSO power supply.

Maryland PSC Case No. 9232, Potomac Electric Power Co. administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

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Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Reply, August 2010; Rebuttal, September 2010; Surrebuttal, November 2010

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Standby rate design. Treatment of uneconomic dispatch costs.

Nova Scotia UARB Case No. NSUARB P-887(2), fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Direct, September 2010.

Effectiveness of fuel-adjustment incentive mechanism.

Manitoba PUB, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystems. Direct, December 2010.

Assessment of drought-related financial risk.

2011 **Mass. DPU 10-170,** NStar–Northeast Utilities merger; Cape Light Compact. Direct, May 2011.

Merger and competitive markets. Competitively neutral recovery of utility investments in new generation.

Mass. DPU 11-5, -6, -7, NStar wind contracts; Cape Light Compact. Direct, May 2011.

Assessment of utility proposal for recovery of contract costs.

Wisc. PSC Docket No. 4220-UR-117, electric and gas rates of Northern States Power: Citizens Utility Board of Wisconsin. Direct, Rebuttals (2) October 2011; Surrebuttal, Oral Sur-Surrebutal November 2011;

Cost allocation and rate design. Allocation of DOE settlement payment.

Wisc. PSC Docket No. 6680-FR-104, fuel-cost-related rate adjustments for Wisconsin Power and Light Company: Citizens Utility Board of Wisconsin. Direct, October 2011; Rebuttal, Surrebuttal, November 2011

Costs to comply with Cross State Air Pollution Rule.

2012 **Maryland PSC** Case No. 9149, Maryland IOUs' development of RFPs for new generation; Maryland Office of People's Counsel. March 2012.

Failure of demand-response provider to perform per contract. Estimation of cost to ratepayers.

PUCO Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, 11-350-EL-AAM, transition to competitive markets for Columbus Southern Power Company and Ohio Power Company; Ohio Consumers' Counsel. May 2012

Structure of auctions, credits, and capacity pricing as part of transition to competitive electricity markets.

Wisconsin PSC Docket No. 3270-UR-118, Madison Gas & Electric rates, Wisconsin Citizens Utility Board. Direct, August 2012; Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 05-UR-106, We Energies rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 4220-UR-118, Northern States Power rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, October 2012; Surrebuttal, November 2012.

Recovery of environmental remediation costs at a manufactured gas plant. Cost allocation and rate design.

2013 **Corporation Commission of Oklahoma** Cause No. PUD 201200054, Public Service Company of Oklahoma environmental compliance and cost recovery, Sierra Club. Direct, January 2013; rebuttal, February 2013; surrebuttal, March 2013.

Economic evaluation of alternative environmental-compliance plans. Effects of energy efficiency and renewable resources on cost and risk.

Maryland PSC Case No. 9324, Starion Energy marketing, Maryland Office of People's Counsel. September 2013.

Estimation of retail costs of electricity supply.

Wisconsin PSC Docket No. 6690-UR-122, Wisconsin Public Service Corporation gas and electric rates, Wisconsin Citizens Utility Board. Direct, August 2013; Rebuttal, Surrebuttal September 2013.

Cost allocation and rate design; rate-stabilization mechanism.

Wisconsin PSC Docket No. 4220-UR-119, Northern States Power Company gas and electric rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, Surrebuttal, October 2013.

Cost allocation and rate design.

Michigan PSC Case No. U-17429, Consumers Energy Company approval for new gas plant, Natural Resources Defense Council. Corrected Direct, October 2013.

Need for new capacity. Economic assessment of alternative resource options.

2014 **Maryland PSC** Case Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, April 2014; surrebuttal, May 2014.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Conn. PURA Docket No. 13-07-18, rules for retail electricity markets; Office of Consumer Counsel. Direct, April 2014.

Estimation of retail costs of power supply for residential standard-offer service.

PUC Ohio Case Nos. 13-2385-EL-SSO, 13-2386-EL-AAM; Ohio Power Company standard-offer service; Office of the Ohio Consumers' Counsel. Direct, May 2014.

Allocation of distribution-rider costs.

Wisc. PSC Docket No. 6690-UR-123, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, August 2014; Surrebuttal, September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 05-UR-107, We Energy biennial review of electric and gas costs and rates; Citizens Utility Board of Wisconsin. Direct, August 2014; Rebuttal, Surrebuttal September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 3270-UR-120, Madison Gas and Electric Co. electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2014.

Cost allocation and rate design.

Nova Scotia UARB Case No. NSUARB P-887(6), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2014.

Allocation of fuel-adjustment costs.

2015 **Maryland PSC** Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Second Reply, June 2015; Second Rebuttal, July 2015.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 6690-UR-124, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2015; Surrebuttal, October 2015.

Cost allocation and rate design.

Wisconsin PSC Docket No. 4220-UR-121, Northern States Power Company gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, October 2015.

Cost allocation and rate design.

Maryland PSC Cases Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Third Reply, September 2015; Third Rebuttal, October 2015.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Nova Scotia UARB Case No. NSUARB P-887(7), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2015.

Accounting adjustment for estimated over-earnings. Proposal for modifying procedures for setting the Actual Adjustment.

2016 **Maryland PSC** Case No. 9406, Baltimore Gas & Electric base rate case; Maryland Office of People's Counsel. Direct, February 2016; Rebuttal, March 2016; Surrebuttal, March 2016.

Allocation of Smart Grid costs. Recovery of conduit fees. Rate design.

Nova Scotia UARB Case No. NSUARB P-887(16), Nova Scotia Power 2017-2019 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, May 2016; Reply, June 2016.

Base Cost of Fuel forecast. Allocation of Maritime Link capital costs. Fuel cost hedging plan.

Wisconsin PSC Docket No. 3270-UR-121, Madison Gas and Electric Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, August 2016; Rebuttal, Surrebuttal, September 2016.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6680-UR-120, Wisconsin Power and Light Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, Sur-surrebuttal, September 2016.

Cost allocation and rate design.

Minnesota PSC Docket No. E002/GR-15-826, Northern States Power Company electric rates; Clean Energy Organizations. Direct, June 2016; Rebuttal, September 2016; Surrebuttal, October 2016.

Cost basis for residential customer charges.

Nova Scotia UARB Case No. NSUARB M07611, Nova Scotia Power 2016 fuel adjustment mechanism audit; Nova Scotia Consumer Advocate. Direct, November 2016.

Sanctions for imprudent fuel-contracting practices.

2017 **Kentucky PSC** Case No. 2016-00370, Kentucky Utilities Company electric rates; Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Kentucky PSC Case No. 2016-00371, Louisville Gas & Electric Company electric rates; Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Massachusetts DPU 17-05, Eversource Energy electric rates; Cape Light Compact. Direct, April 2017; Supplemental Direct, Surrebuttal, August 2017.

Cost Allocation. Cost basis for residential customer charges. Demand charges for net metering customers.

Michigan PSC Case No. U-18255, DTE Electric Company electric rates; Natural Resources Defense Council, Michigan Environmental Council, and Sierra Club. Direct, August 2017.

Cost basis for residential customer charges.

North Carolina NCUC Docket No. E-2, Sub 1142, Duke Energy Progress electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, October 2017.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 44967, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, November 2017.

Cost basis for residential customer charges.

2018 **North Carolina NCUC** Docket No. E-7, Sub 1146, Duke Energy Carolinas electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, January 2018.

Cost basis for residential customer charges.

PUC Ohio Case Nos. 15-1830-EL-AIR, 15-1831-EL-AAM, 15-1832-EL-ATA; Dayton Power and Light Company electric rates; Natural Resources Defense Council. Direct, April 2018.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45029, Indianapolis Power and Light Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, May 2018.

Cost basis for residential customer charges. Design of residential energy rates.

PUC of Texas Docket No. 48401, Texas-New Mexico Power Company electric rates; Office of Public Utility Counsel. Direct, Cross-Rebuttal, August 2018.

Cost of service study. Allocation of requested revenue increase.

West Virginia PSC Case No. 18-0646, Appalachian Power Company and Wheeling Power Company electric rates; Consumer Advocate Division. Direct, Rebuttal, October 2018.

Cost allocation and rate design.

2019 **South Carolina PSC** Docket No. 2018-319-E, Duke Energy Carolinas electric rates; South Carolina State Conference of the NAACP, South Carolina Coastal Conservation League, and Upstate Forever. Direct, February 2019; Surrebuttal, March 2019.

Cost basis for residential customer charges.

South Carolina PSC Docket No. 2018-318-E, Duke Energy Progress electric rates; South Carolina State Conference of the NAACP, South Carolina Coastal Conservation League, and Upstate Forever. Direct, Surrebuttal, March 2019.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45159, Northern Indiana Public Service Company electric rates; Citizens Action Coalition of Indiana. Direct, February 2019; Responsive, June 2019.

Proposed industrial rate restructuring. Allocation of requested revenue increase. Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45235, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana and Indiana Community Action Association. Direct, August 2019; Cross-Answering, September 2019.

Proposed investment in advanced metering infrastructure. Allocation of requested revenue increase. Cost basis for residential customer charges. Design of residential energy rates. Proposed residential demand rate pilot.

Nova Scotia UARB Case No. NSUARB M09288, Nova Scotia Power 2020-2022 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, August 2019.

Proposed residential rates for the Fuel Stability Period. Proposed treatment of excess earnings.

Indiana Utility Regulatory Commission Cause No. 45253, Duke Energy Indiana electric rates; Citizens Action Coalition of Indiana, Indiana Community Action Association, and Environmental Working Group. Direct, October 2019; Cross-Answering, December 2019.

Cost of service study. Allocation of requested revenue increase. Cost basis for residential customer charges. Design of residential energy rates. Proposed revenue decoupling mechanism.

RATE DESIGN 23

The Customer Charge and Problems Of Double Allocation of Costs

By GEORGE J. STERZINGER

AFTER several years of the "great rate debate" attention finally seems to be turning towards a forgotten part of rate design: the customer charge. Utilities, forced by the Public Utility Regulatory Policies Act to justify or do away with declining energy charges, have begun arguing for cost classification and subsequent rate design with increasingly large customer charges. Recently proposed customer charges seem to be consistently in the $6 to $9 range, accompanied by embedded cost-of-service studies supporting even greater charges.

Consumer and environmental groups concerned about rate design reform (rather than using the customer charge as a place to dump costs, as the utilities do) have seen it as a place to shave costs. Concerned primarily with getting a kilowatt-hour or usage charge to reflect incremental or marginal costs more accurately, these groups have attempted to resolve the problem of the resulting excess revenue by proposing that the customer charge be lowered enough to "lose" the surplus. Negative customer charges or lump sum monthly payments from the utility to consumers have been proposed by more imaginative analysts.[1]

Analyses of the proper customer charge have often yielded contradictory results depending upon whether incremental or embedded costs were used. Incremental analyses often, but not always, support low customer charges, while embedded cost analyses often, but not always, support high customer charges.

The importance of incremental price signals and the need to strike a balance between revenue constraints and proper price signals have produced wide agreement that the customer charge is the least "informative" of all parts of a rate design and should be the last place a utility is allowed to collect revenues if incremental costs are found to be useful in designing rates.

Unfortunately, the debate on the proper definition and use of incremental costs remains unresolved, while traditional practices of embedded cost allocation seem to support very high customer charges. Regulators, forced with making a decision, have found some cost basis to be

This article is a critique of the currently most widely used methodology for classifying a portion of electric utility distribution plant as a customer cost. The author argues that this classification, combined with an allocation of the "above minimum" portion on a demand basis, leads to an overallocation of costs to low-use residential customers of the electric system.

George J. Sterzinger is an economist with the New England Regional Energy Project where he specializes in electric utility rate design testimony. In 1979 he became director of the project. The NEREP provides economic, legal, and technical assistance to low-income groups on regulatory utility issues and other energy policy matters. **Mr. Sterzinger** received a BA degree in economics from St. Joseph College, Ransselaer, Indiana, and has completed all requirements but the dissertation for a PhD degree in economics at Purdue University.

[1] "Customer Charges and the Public Utility Regulatory Policies Act," by Edward F. Renshaw and Perry Renshaw, 104 PUBLIC UTILITIES FORTNIGHTLY 17, August 30, 1979, found high customer charges contrary to the intention of PURPA.

preferable to unresolved speculation, and raised the customer charge based on embedded cost-of-service studies.

Since incremental analyses cannot by themselves support a low customer charge, the embedded cost analyses which support high customer charges must also be closely investigated to determine if they meet current objectives of rate design. An examination of these methodologies reveals the following characteristics:

— Almost all of them rely for their justification on the determination of the cost of a minimum distribution system, and the classification of this system as a customer cost.

— Once the classification has been made, it is an inescapable conclusion of the allocated cost-of-service study that calculated customer costs will be substantial.

— However, an examination of the rationale for the classification and the implications of that classification lead equally inescapably to the conclusion that minimum use residential customers will be overcharged by such cost allocation practices.

— The only reasonable remedy for the problem of overcharging is to classify the entire distribution system on a consistent basis, which would be a demand basis.

— Once this is done, traditional cost-of-service studies no longer provide support for high customer charges.

A national survey of utility practices in classification of distribution system costs determine that the great majority used some form of minimum system to classify costs in the relevant Federal Energy Regulatory Commission accounts. (The survey was conducted by Carolina Power and Light Company, Raleigh, North Carolina.) The survey summarized the results of company practices to determine how much, on average, each distribution plant account was classified as demand. The results by FERC account were as follows:

— Account 364 — Poles and fixtures were separated into primary and secondary; the primary portion was split 50-50 between customer and demand costs, the secondary portion was classified 56.5 per cent customer and 43.5 per cent demand.

— Account 365 — Conductors and devices were also separated into primary and secondary; the primary portion was classified 44.3 per cent customer and 55.7 per cent demand, and the secondary portion was classified 46.4 per cent customer and 53.6 per cent demand.

— Account 368 — Line transformers were classified 34 per cent customer and 66 per cent demand.

— Account 369 — Services were classified 70.8 per cent customer and 29.2 per cent demand.

The difficulties with these methodologies only begin with the minimum distribution system. The concept is very difficult to define and consequently susceptible to widely varying interpretations. No single method exists for calculating the cost of this system; nevertheless, a fairly standard approach is to reconstruct the existing distribution system using some type of minimum equipment. Minimum equipment could be of the type employed by the company, currently purchased by the company, currently used in the industry, or currently required by safety code. The cost of this equipment can be either booked or in current prices. Obviously, with this large a menu of definitions to choose from, a utility analyst can calculate costs for these systems over a wide range.

It should be mentioned here that one other method sometimes used to calculate the cost of a minimum system is the "zero-intercept" method whereby regression equations relating cost to various sizes of equipment are derived, and then solved for the cost of zero-sized or "zero-intercept" equipment. The strongest objections to this methodology arise from the limitations on data, the unreliability of the derived equations, and some fundamental problems that arise from making the statistical inference about the cost of the zero-sized equipment.

A typical utility in the sample discussed earlier, faced with the problem of classifying costs in Account 365 —overhead lines, for example, would determine the cost of the minimum equipment needed to replace all existing lines, calculate that cost as a fraction of the total costs of equipment in the account, and use that fraction to classify customer costs. Thus, a utility with 1,000 miles of overhead lines and two types of line costing $1 per foot and $2 per foot would calculate a minimum system cost of roughly $5.28 million ($1 × 5,280 feet per mile × 1,000 miles). This $5.28 million can, of course, be varied if different types of minimum lines are used, or if for other reasons the cost of $1 per foot is changed.

Beyond problems arising from the indeterminate nature of the minimum system, the appropriateness of classifying these costs as customer costs has been long debated. Strictly speaking, customer costs should be limited to those costs which can be shown to vary exclusively with number of customers. Distribution system costs, both as built and hypothetical minimum system, obviously depend to a great extent on geographical considerations — type of terrain and customer density. Several analysts have argued that the nature of cost causation — in this case at least in part due to geography — does not allow the costs to be neatly fit into either demand or customer cost categories; that the costs are simply unallocable. Recent statistical analyses support this notion.[2]

An additional and more severe problem with this methodology arises from the consequences of classifying distribution system costs into both customer and demand portions. Simply put, this practice leads

[2] "The Economics of Electric Distribution System Costs and Investments," by David J. Lessels, 106 PUBLIC UTILITIES FORTNIGHTLY 37, December 4, 1980, found no statistical justification for the classification of distribution costs as customer related.

inevitably to a double allocation and possibly a double collection of these costs from low-use residential customers and a misallocation of costs among customer classes.

To see why this is so, one need only step back for a moment to consider what it is that a cost allocation study attempts to do, and what happens when distribution system costs are split into customer and demand portions and then allocated to individual classes.

An allocation study assigns costs to customers on the basis of usage characteristics; fairness requires that allocated costs follow, as closely as possible, the actual costs of serving customers. Splitting the distribution system into a minimum usage and an above minimum usage portion, and allocating the minimum portion on a customer basis, and the above minimum on a usage basis results in low-use residential customers paying for more of the system than is required to serve them. By splitting the distribution system into two parts, low-use residential consumers are charged twice: once, on a customer basis, for a portion of the system sized to meet their demands; and again on a demand basis for a portion of the system sized to serve demand beyond what would be needed to serve them. The only practical way satisfactorily to assure that low-use customers are charged only once for distribution equipment is to allocate the distribution system costs on a single consistent basis. Of the two considered, customer and demand, it is obvious that only demand can be used to classify and allocate distribution costs on a satisfactory basis.

In order to explain more fully why this method constitutes double charging of low-use customers, we can look more closely at the handling of FERC Accounts 364 and 365 which represent the cost of overhead lines and poles. To illustrate this, suppose the company had only 1,000 miles of overhead lines and 10,000 poles; and in addition it used two types of line — one costing $1 per foot, for 500 miles of overhead, the other costing $2 per foot, for the remainder; and two sizes of pole — 5,000 costing $30 per pole and 5,000 costing $60 per pole. Total cost of this system would be:

a) Line: 500 miles at $1 per foot	$2,640,000	
b) Line: 500 miles at $2 per foot	5,280,000	
Subtotal		$7,920,000
c) Poles: 5,000 poles at $30 per pole	$ 150,000	
d) Poles: 5,000 poles at $60 per pole	300,000	
Subtotal		$ 450,000
Total		$8,370,000

A minimum system in this case would be determined by calculating the cost of the 1,000 miles of overheads if only the minimum-sized line was used, plus the cost of the 10,000 poles if only the minimum-sized pole was used.

Cost of the minimum system is:

a) Line: 1,000 miles at $1 per foot	$5,280,000	
b) Poles: 10,000 poles at $30 per pole	300,000	
Total		$5,580,000

Therefore, the cost of the above minimum (or capacity) system would be the remainder, or $2,780,000.

The minimum system calculated in this fashion could, and actually does, serve a considerable level of usage.

The minimum system is allocated on a customer basis — all customers are charged for an equal share of it. The remainder of the system, the more expensive facilities required to meet loads beyond those handled by minimum-sized equipment, is allocated on some demand basis; noncoincident peak demand is often used. In the calculation of the noncoincident peak demand allocation factors, usage at all levels of the residential and general service customer classes is used to determine allocation factors.

If, for example, the minimum overhead lines, conductors, and poles could supply a demand of two kilowatts per residential customer, that amount of usage would be paid for in the customer charge. In the determination of demand allocation factors, however, each residential customer's demand is calculated and added to determine the portion of the above minimum system costs to be allocated to the residential class and to each customer through the appropriate rates. So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-kilowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account. Even after overcoming all the problems of this approach one is still confronted with the dubious value of charging for equipment on an up-front basis rather than through a per kilowatt-hour charge at a time when conservation is recognized as an important goal of energy policy.

The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies will produce more equitable estimates of the cost of serving low-use residential customers.

Duke Energy Progress
Response to
NCJC Data Request
Data Request No. 4

Docket No. E-2, Sub 1219

Date of Request: **January 29, 2020**
Date of Response: **March 16, 2020**

☐ **CONFIDENTIAL**

X **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached second supplemental response to NCJC Data Request No. 4-16, was provided to me by the following individual(s): Teresa Reed, Rates & Regulatory Strategy Director, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

NCJC
Data Request No. 4
DEP Docket No. E-2, Sub 1219
Item No. 4-16

<u>Request:</u>

4-16. Reference Pirro Exhibit No. 4.
a. Please provide an electronic spreadsheet version of Pirro Exhibit No. 4 with all cell formulas and file linkages intact.
b. Please provide electronic copies of all spreadsheet files linked to the requested electronic spreadsheet version of Pirro Exhibit No. 4.
c. Where file linkages do not exist, please provide detailed descriptions of the sources for all numbers that were calculated elsewhere and copied into the requested electronic spreadsheet version of Pirro Exhibit No. 4.
d. Please provide in an electronic spreadsheet with all cell formulas and file linkages intact a version of Pirro Exhibit 4 based on a cost of service study which classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any distribution plant costs as customer-related based on a minimum system analysis.)
e. Please provide in an electronic spreadsheet with all cell formulas and file linkages intact a version of Pirro Exhibit 4 based on a cost of service study which:
i) Classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any distribution plant costs as customer-related based on a minimum system analysis.)
ii) Allocates demand-related distribution costs based on rate class diversified peak demand (i.e., peak demand for the class as a whole) rather than class non-coincident peak demand (i.e., the sum of individual customers' maximum demand).

<u>Second Supplemental Update 3/16/2020:</u>

Please refer to the "Pirro Supplemental Exhibit 4.xlsx" and "Pirro Exhibit 4 No Min Sys with Revised fuel corr .xlsx" files for the Pirro 4 files with and without the minimum system approach, revised to be consistent with supplemental version of Pirro 4.

Pirro Exhibit 4 No Min Sys with Revise(

Pirro Supplemental Exhibit 4.xlsx

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
NC RETAIL COST OF SERVICE - PRESENT - 1CP SUMMER
For the test year ending December 31, 2018
(DOLLARS IN THOUSANDS)

Without MINIMUM SYSTEM
SPREAD OF PROPOSED INCREASE TO CUSTOMER CLASSES: REVISED FOR FUEL CHANGES

		Present Revenue Run: E-1 Item 45b						25%								
Line		Annualized Rate Base	Present Rates Revenues Excl Riders	Present Net Operating Income	Present ROR	Gross Revenues At Average ROR	Variance From The Average	Reduction in Variance From The Average	Proposed Rate Increase Before Reduction in Variance	Proposed Rate Increase After Reduction in Variance	Total Adjusted Present Rates Revenues Incl Riders	Adjusted Proposed Percent Increase	ROR At Proposed Rates	Sum of Additional Rider Impacts	Proposed Rate Increase incl. Rider Impacts	Proposed Percent Increase incl. EDIT riders
No.	Rate Class	(A)	(B)	(C)	(D) = (C) / (A)	(E)	(F)=(B)- (E)	(G) = - (F) * 25%	(H)	(I) = (H) + (G)	(J) = (V) / (T)	(K) = (I) / (J)	(L)	(M) = (AB)	(N) = (I) + (M)	(O) = (N) / (J)
1	**RES**	$ 5,811,635	$ 1,607,900	$ 192,937	3.32%	$ 1,606,430	$ 1,470	$ (367)	$ 315,710	$ 315,343	$ 1,879,740	**16.8%**	7.43%	$ (66,952)	$ 248,391	13.2%
2	**SGS**	$ 643,218	$ 191,921	$ 26,412	4.11%	$ 185,175	$ 6,746	$ (1,686)	$ 34,942	$ 33,256	$ 233,942	**14.2%**	8.01%	$ (7,613)	$ 25,642	11.0%
3	**SGSCLR**	$ 5,753	$ 3,245	$ 858	14.92%	$ 2,375	$ 870	$ (217)	$ 313	$ 95	$ 4,246	**2.2%**	16.06%	$ (72)	$ 23	0.5%
4	**MGS**	$ 2,596,836	$ 816,427	$ 65,368	2.52%	$ 842,899	$ (26,472)	$ 6,618	$ 141,070	$ 147,688	$ 959,944	**15.4%**	6.83%	$ (28,716)	$ 118,972	12.4%
5	**LGS**	$ 1,314,327	$ 471,131	$ 37,369	2.84%	$ 478,951	$ (7,821)	$ 1,955	$ 71,399	$ 73,355	$ 575,133	**12.8%**	7.07%	$ (13,870)	$ 59,485	10.3%
6	**SI**	$ 23,748	$ 5,089	$ 437	1.84%	$ 5,540	$ (451)	$ 113	$ 1,290	$ 1,403	$ 5,859	**23.9%**	6.33%	$ (255)	$ 1,148	19.6%
7	**TSS**	$ 621	$ 440	$ 108	17.45%	$ 326	$ 114	$ (29)	$ 34	$ 5	$ 563	**0.9%**	17.95%	$ (7)	$ (2)	-0.3%
8	**ALS, SLS**	$ 388,987	$ 88,396	$ 32,516	8.36%	$ 62,785	$ 25,612	$ (6,403)	$ 21,131	$ 14,728	$ 92,721	**15.9%**	11.18%	$ (4,843)	$ 9,885	10.7%
9	**SFL**	$ 1,318	$ 205	$ (9)	-0.66%	$ 273	$ (68)	$ 17	$ 72	$ 89	$ 220	**40.3%**	4.46%	$ (14)	$ 75	34.1%
	TOTAL RETAIL	**$ 10,786,444**	**$ 3,184,754**	**$ 355,997**	**3.30%**	**$ 3,184,754**	**$ (0)**	**$ 0**	**$ 585,961**	**$ 585,961**	**$ 3,752,367**	**15.6%**	**7.41%**	**$ (122,342)**	**$ 463,619**	**12.4%**

Calculations for Rate Design in Order to Apply Increase to Unadjusted Billing Determinents

Present Revenue Run: E-1 Item 45b — E-1 Item 42c

Line No.	Rate Class	Proposed Rate Increase After Reduction in Variance (P) = (I)	Customer Growth Adjustment in Present Revenues (Q)	Weather Normalization Adjustment in Present Revenues (R)	Total Adjustments to Exclude for Rate Design (S) = (Q) + (R)	Ratio of Unadjusted Present Revenues to Adjusted (T) = [(B) - (S)] / (B)	Target Revenue Increase for Rate Design (to be applied to unadjusted billing determinents) (U) = (P) x (T)	Total Unadjusted Present Rates Revenues Including Riders (V)	Proposed Percent Increase to unadjusted Revenues for Rate Design (W) = (U) / (V)	Target Revenue Increase for Rate Design plus Sum of Additional Rider Impacts (X) = (U) + (M)
10	**RES**	$ 315,343	$ (8,357)	$ (54,752)	$ (63,109)	103.925%	327,720	1,953,518	**16.8%**	$ 260,768
11	**SGS**	$ 33,256	$ 1,107	$ (20,163)	$ (19,056)	109.929%	36,558	257,170	**14.2%**	$ 28,944
12	**SGSCLR**	$ 95	$ 43	$ (338)	$ (295)	109.100%	104	4,632	**2.2%**	$ 31
13	**MGS**	$ 147,688	$ 10,064	$ (1,470)	$ 8,594	98.947%	146,134	949,840	**15.4%**	$ 117,418
14	**LGS**	$ 73,355	$ 2,131	$ (674)	$ 1,457	99.691%	73,128	573,355	**12.8%**	$ 59,258
15	**SI**	$ 1,403	$ 373	$ -	$ 373	92.662%	1,300	5,429	**23.9%**	$ 1,045
16	**TSS**	$ 5	$ 5	$ -	$ 5	98.798%	5	557	**0.9%**	$ (2)
17	**ALS, SLS**	$ 14,728	$ (171)	$ -	$ (171)	100.194%	14,757	92,900	**15.9%**	$ 9,914
18	**SFL**	$ 89	$ 3	$ -	$ 3	98.474%	87	217	**40.3%**	$ 74
	TOTAL RETAIL	**$ 585,961**	**$ 5,199**	**$ (77,398)**	**$ (72,199)**	**102.267%**	**$ 599,792**	**$ 3,837,617**	**15.6%**	**$ 477,449**

Summary of Additional Rider Impacts

Line No.	Rate Class	Per Smith Exh 3 Change in 2018 NC EDIT-1 Rider (Y)	Per Smith Exh 4 Proposed Federal EDIT-2 Rider (Z)	Per Smith Exh 5 Proposed Regulatory Asset and Liability Rider (AA)	Sum of Additonal Rider Impacts (AB) = (X) + (Y) + (Z)
19	**RES**	3,071	$ (69,123)	$ (901)	$ (66,952)
20	**SGS**	373	$ (7,881)	$ (105)	$ (7,613)
21	**SGSCLR**	6	$ (76)	$ (2)	$ (72)
22	**MGS**	2,200	$ (30,312)	$ (604)	$ (28,716)
23	**LGS**	1,643	$ (15,056)	$ (457)	$ (13,870)
24	**SI**	10	$ (263)	$ (2)	$ (255)
25	**TSS**	1	$ (8)	$ (0)	$ (7)
26	**ALS, SLS**	76	$ (4,900)	$ (19)	$ (4,843)
27	**SFL**	0	$ (14)	$ (0.06)	$ (14)
	TOTAL RETAIL	**$ 7,381**	**$ (127,633)**	**$ (2,091)**	**$ (122,342)**

CAC
IURC Cause No. 45253
Data Request Set No. 12
Received: September 23, 2019

CAC 12.4

Request:

Please reference Diaz Revised Direct, p. 30, ll. 4-19.

a) Please confirm that all production plant costs are classified as demand-related in the retail cost of service study.

b) Please indicate whether secondary pole, conductor, and transformer plant costs are classified in the retail cost of service study as facility-related or connection-related.

c) Please indicate whether secondary pole, conductor, and transformer costs are allocated based on number of customers, diversified class demand, or non-coincident peak demand.

d) For those instances where a secondary transformer serves more than one customer, does the Company size the transformer to serve the expected diversified load on the transformer or the expected sum of the individual customer maximum loads on the transformer? Please explain.

e) Please provide copies of any planning documents or engineering design guidelines which describe Company practice with regard to sizing of secondary transformers.

Response:

a) Yes, all production plant as categorized in the FERC Electric Plant Chart of Accounts in the Uniform System of Accounts is classified as demand related in the retail cost of service study.

b) Secondary pole, secondary conductor, and secondary transformer plant costs are are included in Total Connection Charges. Also included in Total Connection Charges are "fixed connection charges", "services", "secondary line transformers", and "secondary lines". In Diaz Revised Direct p. 30, lines 16-17, Diaz states that "connection-related charges include electric meters and customer accounts"; in this context, Witness Diaz is referring to the "fixed connection charge" component only. The fixed connection charges, as used by rate design to develop the customer charge, do <u>not</u> include secondary pole, secondary conductor, and secondary transformer plant costs in the customer charge.

c) These costs were allocated to retail customers based on Non-coincident peak demand allocators.

d) We use a diversified load on calculation, built into our Secondary Electrical Design System (SEDS) software, when sizing transformers that serve more than one customer.

e) Transformers serving residential load/customers are sized based on diversified load according to coincidence factors and total numbers of customers per transformer. The diversified load shall not exceed our transformer loading guidelines. However, total connected load can't exceed the cold load pick up guidelines (loss of diversity). Also, flicker needs to be evaluated based on guideline below (not to exceed 4.2%).

Taken from a section of the job aid for SEDS:

Residential Transformer Loading Summary

Maximum Transformer Loading

	Summer	Winter
Carolinas	140%	170%
Midwest	145%	185%

Power Factor - 95%

Locked Rotor Amps

Tonnage	1.5	2	2.5	3	3.5	4	5
	48	63	77	93	112	137	160

Maximum Allowable Flicker – 4.2%

Cold Load (loss of diversity) - Summer – 225%, Winter – 270%

Air Conditioner

Ton	AC	Range/Oven	Misc Load	Total Load (KW)
1.5	1.9	3.0	1.5	6.6
2	2.6	3.0	1.5	7.3
2.5	3.2	3.0	1.5	8.0
3	3.9	3.0	1.5	8.7
3.5	4.5	3.0	1.5	9.4
4	5.2	3.0	2.0	10.6
5	6.5	3.0	2.5	12.5

Heat Pump

Ton	H.P.	Strip	Wtr Htr	Misc Load	Total Load (KW)
1.5	1.9	5	4.5	1.5	13.1
2	2.6	10	4.5	1.5	18.8
2.5	3.2	10	4.5	1.5	19.5
3	3.9	10	4.5	1.5	20.2
3.5	4.5	10	4.5	1.5	20.9
4	5.2	15	4.5	2.0	27.1
5	6.5	15	4.5	2.5	29.0

Assumed load per ton (A/C or Heat Pump) – 1.4KW

Diversity (Coincidence Factor)

Carolinas

Customers	Heat Pump	A/C
1	1	1
2	.695	.82
3	.568	.73
4	.486	.645
5	.427	.58
6	.377	.515
7	.352	.49
8	.337	.475
9	.323	.47
10	.314	.46
11	.314	.46
12 & up	.314	.46

Midwest

Customers	Heat Pump or A/C
1	1
2	.8
3	.6
4	.5
5	.45
6 & up	.4

Witness: Diaz for a-c, Abbott/Hart for d-e.

Duke Energy Progress
Response to
NCJC Data Request
Data Request No. 4

Docket No. E-2, Sub 1219

Date of Request: January 29, 2020
Date of Response: February 10, 2020

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 4-5, was provided to me by the following individual(s): Sumita M. Deshmukh, Rates & Regulatory Strategy Manager, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

NCJC
Data Request No. 4
DEP Docket No. E-2, Sub 1219
Item No. 4-5

Request:

4-5. Reference the response to NCUC Form E-1 Data Request, Item No. 45(c).

a. Please provide electronic spreadsheet versions, with all cell formulas and file linkages intact, of the COSS and Allocators reports for the "Summer CP" scenario.

b. Please provide electronic copies of all spreadsheet files linked to the requested electronic spreadsheets.

c. Where file linkages do not exist, please provide detailed descriptions of the sources for all numbers that were calculated elsewhere and copied into the requested electronic spreadsheet versions of the COSS and Allocators reports for the "Summer CP" scenario.

d. Please provide in electronic spreadsheets with all cell formulas and file linkages intact versions of the COSS and Allocators reports for the "Summer CP" scenario based on a cost of service study which classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any distribution plant costs as customer-related based on a minimum system analysis.)

e. Please provide in electronic spreadsheets with all cell formulas and file linkages intact versions of the COSS and Allocators reports for the "Summer CP" scenario based on a cost of service study which:

i) Classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any distribution plant costs as customer-related based on a minimum system analysis.)

ii) Allocates demand-related distribution costs based on rate class diversified peak demand (i.e., peak demand for the class as a whole) rather than class non-coincident peak demand (i.e., the sum of individual customers' maximum demand).

Response:

a) and b): Please refer to the excel versions of the Company's filings under E-1 Item 45C and 45F provided in response to PS DR 1-7.

These include the Excel file 'DEP Rate Case E1 Item 45C 1CP 2018 Adj Prop COS' which contains the requested COSS. Please refer to the response to NCJC 4-4b for the allocation factor files.

c. Please refer to DEP's response to CUCA DR 1-30, which provides the files supporting the Company's per book allocation factors, per book financial inputs, pro forma adjustments and the proposed increase impacts spread across rate classes, along with descriptions.

d. & e (i) Please refer to DEP's response to PS DR 60-15, which contains this COSS in the "DEP PS DR 60-15 1CP No Min Sys Bundled COSS Prop Rates.xls" file.

The allocation factors for this "no minimum system" scenario are provided in the response to NCJC DR 4-4d. Allocators for E1 Item 45B and 45C are both based on allocations in the per books cost of service.

e (ii). The Company has not prepared the requested analysis.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 60

Docket No. E-2, Sub 1219

Date of Request:	**January 8, 2020**
Date of Response:	**January 17, 2020**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 60-15, was provided to me by the following individual(s): <u>Sumita M. Deshmukh, Rates & Regulatory Strategy Manager,</u> and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Senior Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 60
DEP Docket No. E-2, Sub 1219
Item No. 60-15
Page 1 of 1

Request:

15. Please provide a calculation for the "minimum intercept method" and the "basic customer method" of apportioning distribution system costs as customer or demand-related. The Company's response should be accompanied by workpapers showing the calculations. The Company's response may refer to information or workpapers provided to the Public Staff in response to the Public Staff's report filed March 28, 2019 in Docket No. E-100, Sub 162.

Response:

DEP has not done a minimum system calculation using the “minimum intercept method” because the Company’s fixed asset system does not contain sufficient detail required to calculate this method. Unit costs applying the basic customer method to the adjusted cost of service at proposed rates under the 1 summer CP allocation method can be found below row 77 of the attached “DEP PS DR 60-15 No Min Sys Unit Costs.xlsx“ file.

The supporting bundled and unbundled cost of service studies for this scenario have also been attached with this response.

DEP PS DR 60-15 No Min Sys Unit Costs.x | DEP PS DR 60-15 1CP No Min Sys Unb | DEP PS DR 60-15 1CP No Min Sys Bun

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2 Sub 1219 E1 Item #45E "Proforma Adjusted at Proposed Rates"
NORTH CAROLINA RETAIL COST OF SERVICE STUDY
TEST YEAR ENDING DECEMBER 31 2018
Summer 1 CP Demand Allocation without Minimum System
PS DR 60-15 Unit Costs

		NC	NC	NC	NC	NC	NC	NC	NC	NC	NC	NC
UNIT COST DETAIL - REVENUES		RETAIL	RES	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
TOTAL FUNCTIONALIZED REVENUES	PROD_DEMAND	1,275,538,882	639,402,155	80,769,176	905,968	352,104,522	201,332,939	869,511	145,688	7,825	1,089	9
	PROD_ENERGY	1,512,477,135	656,508,987	78,062,438	1,255,277	469,301,676	290,835,678	1,872,726	193,094	11,071,607	3,331,624	44,027
	TRANSMISSION	186,475,334	93,532,631	11,996,087	154,578	50,577,169	30,066,058	123,084	25,728	0	0	0
	DIST_SUBS	81,406,095	52,408,702	5,084,567	30,209	15,164,105	7,575,443	467,935	5,063	528,573	102,350	39,147
	DIST_PRIMARY	392,193,924	264,276,209	25,445,248	138,255	77,189,678	19,550,876	2,405,131	22,668	2,431,815	524,540	209,504
	DIST_L_XFMR	95,246,543	64,621,258	6,313,624	39,082	18,581,662	4,312,521	564,733	6,615	681,965	125,082	0
	DIST_SEC_SERV	202,676,871	85,139,687	8,186,606	45,195	18,858,642	0	270,201	7,436	55,260,408	34,908,696	0
	CUSTOMER	179,320,823	147,345,755	19,960,184	950,910	9,716,750	935,406	186,532	61,351	15,565	133,905	14,466
	Total	3,925,335,607	2,003,235,384	235,817,930	3,519,474	1,011,494,205	554,608,921	6,759,852	467,641	69,997,759	39,127,286	307,153
TOTAL SALES OF ELECTRICITY	PROD_DEMAND	1,269,669,429	635,600,364	80,257,511	895,504	351,093,830	200,802,688	866,547	144,062	7,825	1,089	9
	PROD_ENERGY	1,500,198,934	653,978,414	77,224,807	1,223,343	468,748,807	286,419,607	1,869,563	189,398	8,959,675	1,541,546	43,777
	TRANSMISSION	179,121,483	89,761,770	11,524,991	149,594	48,597,739	28,944,364	118,047	24,978	0	0	0
	DIST_SUBS	80,307,201	51,657,066	5,011,361	29,704	14,988,062	7,489,454	462,075	4,984	524,808	101,130	38,556
	DIST_PRIMARY	377,823,908	254,438,803	24,511,367	133,632	74,488,066	18,943,940	2,317,270	21,969	2,373,131	394,851	200,880
	DIST_L_XFMR	93,800,083	63,591,131	6,213,371	38,404	18,333,807	4,260,250	556,605	6,508	676,645	123,362	0
	DIST_SEC_SERV	200,797,918	84,255,276	8,099,492	44,536	18,718,727	0	268,003	7,333	54,862,973	34,541,578	0
	CUSTOMER	172,270,753	141,377,029	19,154,715	914,435	9,498,835	928,901	181,857	57,673	15,565	127,696	14,046
	Total	3,873,989,709	1,974,659,853	231,997,614	3,429,152	1,004,467,874	547,789,204	6,639,967	456,904	67,420,622	36,831,251	297,268
NON REQ'T SALES REVENUE	PROD_DEMAND	4,817,627	2,389,495	294,137	2,421	1,357,641	770,167	3,415	351	0	0	0
	PROD_ENERGY	130,052,588	56,205,112	6,579,490	106,617	37,638,146	28,168,655	144,595	16,035	903,123	287,021	3,793
	TRANSMISSION	45,117	22,377	2,755	23	12,714	7,213	32	3	0	0	0
	DIST_SUBS	0	0	0	0	0	0	0	0	0	0	0
	DIST_PRIMARY	0	0	0	0	0	0	0	0	0	0	0
	DIST_L_XFMR	0	0	0	0	0	0	0	0	0	0	0
	DIST_SEC_SERV	0	0	0	0	0	0	0	0	0	0	0
	CUSTOMER	0	0	0	0	0	0	0	0	0	0	0
	Total	134,915,331	58,616,985	6,876,382	109,061	39,008,501	28,946,034	148,042	16,389	903,123	287,021	3,793
FUNCTIONALIZED REQ'TS RATE SCHED REV	PROD_DEMAND	1,264,851,802	633,210,869	79,963,374	893,083	349,736,190	200,032,521	863,132	143,711	7,825	1,089	9
	PROD_ENERGY	1,370,146,347	597,773,302	70,645,316	1,116,725	431,110,660	258,250,953	1,724,968	173,362	8,056,552	1,254,525	39,983
	TRANSMISSION	179,076,366	89,739,392	11,522,236	149,571	48,585,025	28,937,152	118,015	24,975	0	0	0
	DIST_SUBS	80,307,201	51,657,066	5,011,361	29,704	14,988,062	7,489,454	462,075	4,984	524,808	101,130	38,556
	DIST_PRIMARY	377,823,908	254,438,803	24,511,367	133,632	74,488,066	18,943,940	2,317,270	21,969	2,373,131	394,851	200,880
	DIST_L_XFMR	93,800,083	63,591,131	6,213,371	38,404	18,333,807	4,260,250	556,605	6,508	676,645	123,362	0
	DIST_SEC_SERV	200,797,918	84,255,276	8,099,492	44,536	18,718,727	0	268,003	7,333	54,862,973	34,541,578	0
	CUSTOMER	172,270,753	141,377,029	19,154,715	914,435	9,498,835	928,901	181,857	57,673	15,565	127,696	14,046
	Total	3,739,074,378	1,916,042,868	225,121,232	3,320,091	965,459,373	518,843,170	6,491,925	440,515	66,517,499	36,544,230	293,474
Revenues for Rate Design: Including Proposed Increase												
Present Revenues per Pirro Exhibit 4, col. (B)		3,160,649,746	1,605,490,440	192,929,820	3,261,129	818,808,517	445,917,273	5,098,850	442,999	62,409,821	26,085,299	205,598
Minus: Adjustments to Exclude per Pirro Exhibit 4, col. (S)		72,209,674	63,014,384	19,155,966	296,747	(8,622,376)	(1,423,708)	(374,132)	(5,324)	120,775	50,480	(3,137)
Plus: Target Revenue Increase for Rate Design per Pirro Exhibit 4, col. (U)		599,783,973	327,722,883	36,559,280	103,715	146,134,249	73,112,288	1,300,002	1,449	10,411,311	4,351,593	87,202
Proposed Revenues for Rate Design		3,832,643,393	1,996,227,708	248,645,065	3,661,591	956,320,390	517,605,853	6,024,720	439,123	72,941,907	30,487,373	289,663

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2 Sub 1219 E1 Item #45E "Proforma Adjusted at Proposed Rates"
NORTH CAROLINA RETAIL COST OF SERVICE STUDY
TEST YEAR ENDING DECEMBER 31 2018
Summer 1 CP Demand Allocation without Minimum System
PS DR 60-15 Unit Costs

UNIT COST DETAIL - REVENUES		NC RETAIL	NC RES	NC SGS	NC SGSCLR	NC MGS	NC LGS	NC SI	NC TSS	NC ALS	NC SLS	NC SFL
FUNCT REQ'TS RATE SCHED REV for RATE DESIGN	PROD_DEMAND	1,296,504,271	659,710,230	88,319,072	984,945	346,425,607	199,555,491	801,015	143,257	8,581	908	9
	PROD_ENERGY	1,404,433,775	622,789,629	78,027,333	1,231,590	427,029,792	257,635,086	1,600,827	172,815	8,834,672	1,046,600	39,464
	TRANSMISSION	183,557,689	93,494,913	12,726,242	164,956	48,125,122	28,868,143	109,522	24,896	0	0	0
	DIST_SUBS	82,316,860	53,818,873	5,535,018	32,760	14,846,186	7,471,593	428,821	4,968	575,495	84,369	38,056
	DIST_PRIMARY	387,278,818	265,086,861	27,072,659	147,377	73,782,966	18,898,763	2,150,503	21,900	2,602,333	329,408	198,271
	DIST_L_XFMR	96,147,397	66,252,368	6,862,631	42,355	18,160,261	4,250,090	516,548	6,487	741,997	102,916	0
	DIST_SEC_SERV	205,822,815	87,781,291	8,945,841	49,117	18,541,537	0	248,716	7,309	60,161,761	28,816,642	0
	CUSTOMER	176,581,768	147,293,543	21,156,269	1,008,493	9,408,920	926,686	168,769	57,491	17,068	106,531	13,864
	Total	3,832,643,393	1,996,227,708	248,645,065	3,661,591	956,320,390	517,605,853	6,024,720	439,123	72,941,907	30,487,373	289,663
FUNCT REVENUE for RATE DESIGN	**Demand**	2,251,627,851	1,226,144,536	149,461,463	1,421,508	519,881,679	259,044,081	4,255,124	208,817	64,090,166	29,334,242	236,335
	Energy	1,404,433,775	622,789,629	78,027,333	1,231,590	427,029,792	257,635,086	1,600,827	172,815	8,834,672	1,046,600	39,464
	Customer	176,581,768	147,293,543	21,156,269	1,008,493	9,408,920	926,686	168,769	57,491	17,068	106,531	13,864
		3,832,643,393	1,996,227,708	248,645,065	3,661,591	956,320,390	517,605,853	6,024,720	439,123	72,941,907	30,487,373	289,663
Billing Determinants	Summer CP kW (DP adj @ meter)		3,690,872	454,333	3,739	2,099,254	1,204,485	5,292				
	Adj kWh Sales (E2 at meter)		16,666,046,589	1,950,982,004	31,614,397	11,178,964,878	8,457,791,022	43,075,313	4,754,792			1,134,908
	Year End No. Cust (C1)		1,199,988	160,062	6,011	38,728	279	851	780			78
Unit Cost per Billing Determinants												
	Demand $/kW-Month		27.68	27.41	31.68	20.64	17.92	67.00	N/A	N/A	N/A	N/A
	Energy ¢/kWh		3.74	4.00	3.90	3.82	3.05	3.72	3.63	N/A	N/A	3.48
	Cust $/Month		10.23	11.01	13.98	20.25	276.79	16.53	6.14	N/A	N/A	14.81
Unit Costs - ¢/kWh	Demand		7.36	7.66	4.50	4.65	3.06	9.88	4.39	N/A	N/A	20.82
	Energy		3.74	4.00	3.90	3.82	3.05	3.72	3.63	N/A	N/A	3.48
	Customer		0.88	1.08	3.19	0.08	0.01	0.39	1.21	N/A	N/A	1.22
	Total		11.98	12.74	11.58	8.55	6.12	13.99	9.24	N/A	N/A	25.52

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Duke Energy Progress
Response to
NCJC Data Request
Data Request No. 4

Docket No. E-2, Sub 1219

Date of Request: January 29, 2020
Date of Response: February10, 2020

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 4-1, was provided to me by the following individual(s): Teresa Reed, Rates & Regulatory Strategy Director, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

NCJC
Data Request No. 4
DEP Docket No. E-2, Sub 1219
Item No. 4-1
Page 1 of 1

Request:

4-1. Reference the response to NCUC Form E-1 Data Request, Item No. 42 (revised).
a. Please provide an electronic spreadsheet version of the response to Item No. 42(c) with all cell formulas and file linkages intact.
b. Please provide electronic copies of all spreadsheet files linked to the requested electronic spreadsheet version of the response to Item No. 42(c).
c. Reference the response to NCUC Form E-1 Data Request, Item No. 43. Please provide an electronic spreadsheet with the forecast of annual residential sales (MWh) before energy efficiency impacts, energy efficiency impacts, and after energy efficiency impacts.

Response:

a. Please see tab 'E-1 Item 42c (Adjustments) in the attached workbook "NCJC DR 4-1 Supplement North Carolina 2019 Rate Case Billing Determinants Revised Base Rate.xlsx" for the revised file. The original file was contained in PS 1-7 Native Files.

NCJC DR 4-1
Supplement North C

b. 'E-1 Item 42c (Adjustments)' was provided in answer "a" above in electronic spreadsheet format with all cell formulas and file linkages intact.

c. Please see the attached Excel file "NCJC DR 4-1 NCUC Form E-1 Data Request Item No. 43 - Annual MWH Res Sales UEE.xlsx" for the requested data.

NCJC DR 4-1 NCUC
Form E-1 Data Requ

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
NCJC Data Request 4-1c Reponse

DEP NCUC Form E-1 Data Request, Item No. 43: Annual Residential Sales (MWHs) - Before Impacts, UEE Impacts, After Impacts

Year	Residential Sales Before UEE	UEE Impacts	Residential Sales After UEE
2020	19,248,345	(139,130)	19,109,215
2021	19,390,376	(209,621)	19,180,756
2022	19,627,374	(272,598)	19,354,776
2023	19,920,399	(329,402)	19,590,997
2024	20,279,151	(386,527)	19,892,625
2025	20,625,785	(446,808)	20,178,978
2026	20,998,269	(506,886)	20,491,383
2027	21,368,614	(566,758)	20,801,856
2028	21,762,860	(615,251)	21,147,610
2029	22,094,034	(650,001)	21,444,033
2030	22,442,615	(679,243)	21,763,372
2031	22,795,306	(701,830)	22,093,475
2032	23,181,231	(715,504)	22,465,727
2033	23,527,326	(724,463)	22,802,863
2034	23,923,268	(731,764)	23,191,503

Sharon L. Nelson, Chairman
Richard D. Casad, Commissioner
A. J. "Bud" Pardini, Commissioner

Found in Box 27

(?)

EXHIBIT JFW-9

STATE OF WASHINGTON

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

P.O. Box 9022 • 1300 S. Evergreen Park Dr. S.W. • Olympia, Washington 98504-9022 • (206) 753-6423 • (SCAN) 234-6423

REF:6-1132

June 11, 1992

Mr. Julian Ajello
California PUC
505 Van Ness Avenue
San Francisco, California 94102

Dear Mr. Ajello:

Please accept this belated response to your request for review of the February, 1991 draft of the new NARUC Electric Utility Cost Allocation Manual. Our staff recognizes that the final has now been printed. However, the inconsistent treatment of customer related costs in the manual is of concern. In three areas, three different approaches are presented. The first is an energy weighted approach, the second the so-called "minimum-system" or "zero-intercept" method, and the last is the "basic customer" method.

At page 39 of the draft, distribution plant is identified as being customer, demand, and energy-related. That is consistent with the treatment of gas distribution plant by this Commission, where it has ordered that 50% of distribution mains be treated as commodity-related. Our Commission has not made specific findings on electric distribution plant, except as set forth below.

At pages 91-100 of the draft, the minimum-system and zero intercept methods are presented. These methods do not conform to the matrix on page 39, which incorporates an energy component of distribution plant. Unfortunately, these two methods are the only methods presented. These are the two methods our Commission has explicitly rejected.

Finally, at page 148, in the section on marginal cost determination, the "basic customer" method, counting as customer related costs only meters, services, meter reading, and billing, is identified and defended.

Previous drafts included additional methods which are missing from the final version. For example, the 10/31/88 draft discussed at the fall meeting in San Francisco contained a section explicitly setting forth the basic customer method in the embedded cost section. In November of 1988, a section discussing the energy-weighted method was distributed to the Committee.

Mr. Julian Ajello
June 11, 1992
Page 2

Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" and "minimum-intercept" methods are not acceptable, and that the only costs which should be considered customer-related are the costs of meters, services, meter reading and billing. Our staff believes that is the most common approach taken by Commissions around the country. For example, in Iowa, the administrative rules of the Commission set this forth explicitly, while in Arizona and Illinois, the Commissions have explicitly rejected the minimum-system or minimum-intercept methods in favor of the basic customer approach.

In gas cost of service, our Commission has explicitly found that distribution plant (including service connections) is partially demand-related and partially commodity related, consistent with the matrix on page 39. The corresponding plant on the electric side -- poles, conductors and transformers -- has not been positively resolved in any cases to date. A recently filed electric cost of service case will provide an opportunity for advocates of the demand-only allocation approach and those favoring an energy weighing approach to make their cases before the Commission.

We hope that it is possible to either correct future editions of the Manual to reflect the variety of approaches to determining customer-related costs, or to even issue a correction to this edition.

Please feel free to contact Bruce Folsom at (206) 586-1132 with any questions you may have.

Sincerely,

Paul Curl

Paul Curl
Secretary