OFFICIAL COPY

FILED

OCT 19 2020

Clerk's Office
N.C. Utilities Commission

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: 9:00 a.m. – 12:30 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: 13

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: 171
PREFILED PAGES: 732
TOTAL PAGES: 903
DATE FILED: October 7, 2020

PLACE: Held via Videoconference REDACTED

DATE: Wednesday, September 30, 2020

TIME: 9:00 A.M. - 12:30 P.M.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

Noteworthy Reporting Services, LLC

DOCKET NO. 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 13

A P P E A R A N C E S:

FOR DUKE ENERGY PROGRESS, LLC:

Camal Robinson, Esq., Associate General Counsel
Brian Heslin, Esq., Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

Lawrence B. Somers, Esq., Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street
Raleigh, North Carolina 27601

James H. Jeffries, IV, Esq.
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

Andrea Kells, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

Molly McIntosh Jagannathan, Esq., Partner
Kiran H. Mehta, Esq., Partner
Troutman Pepper Hamilton Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

Brandon F. Marzo, Esq.
Troutman Pepper
600 Peachtree Street, NE, Suite 3000
Atlanta, Georgia 30308

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II and III:

Christina D. Cress, Esq.
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Robert F. Page, Esq.
Crisp & Page, PLLC
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd:

FOR NC JUSTICE CENTER, NC HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL and SOUTHERN ALLIANCE FOR CLEAN ENERGY:

Gudrun Thompson, Esq., Senior Attorney
David L. Neal, Esq., Senior Attorney
Tirrill Moore, Esq., Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR SIERRA CLUB:

Bridget Lee, Esq.
Sierra Club
9 Pine Street
New York, New York 10005

Catherine Cralle Jones, Esq.
Law Office of F. Bryan Brice, Jr.
127 W. Hargett Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

FOR NC WARN:
Matthew D. Quinn, Esq.
Lewis & Roberts PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR FAYETTEVILLE PUBLIC WORKS COMMISSION:
James West, Esq., General Counsel
955 Old Wilmington Road
Fayetteville, North Carolina 28301

FOR UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES:
Emily Medlyn, Esq., General Attorney
United States Army Legal Services Agency
9275 Gunston Road, Suite 4300 (ELD)
Fort Belvoir, Virginia 22060

FOR VOTE SOLAR:
Thadeus B. Culley, Esq., Regulatory Counsel
Senior Regional Director
1911 Ephesus Church Road
Chapel Hill, North Carolina 27517

A P P E A R A N C E S Cont'd:

FOR NORTH CAROLINA LEAGUE OF MUNICIPALITIES:
Deborah Ross, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Peter H. Ledford, Esq., General Counsel
Benjamin Smith, Esq., Regulatory Counsel
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR THE COMMERCIAL GROUP:
Alan R. Jenkins, Esq.
Jenkins At Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

Brian O. Beverly, Esq.
Young Moore and Henderson, P.A.
3101 Glenwood Avenue
Raleigh, North Carolina 27622

A P P E A R A N C E S Cont'd:

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Karen Kemerait, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR HARRIS TEETER:
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
Boehm, Kurtz, & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

Benjamin M. Royster, Esq.
Royster and Royster, PLLC
851 Marshall Street
Mount Airy, North Carolina 27030

A P P E A R A N C E S Cont'd:

FOR HORNWOOD, INC.:

Janessa Goldstein, Esq.
Corporate Counsel
Utility Management Services, Inc.
6317 Oleander Drive, Suite C
Wilmington, North Carolina 28403

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

Margaret A. Force, Esq., Assistant Attorney General
Teresa Townsend, Esq., Special Deputy Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27603

A P P E A R A N C E S Cont'd:

FOR THE USING AND CONSUMING PUBLIC:

Dianna W. Downey, Esq.

Elizabeth D. Culpepper, Esq.

Layla Cummings, Esq.

Lucy E. Edmondson, Esq.

William E. Grantmyre, Esq.

Gina C. Holt, Esq.

Tim R. Dodge, Esq.

Megan Jost, Esq.

John D. Little, Esq.

Nadia L. Luhr, Esq.

Public Staff - North Carolina Utilities Commission

4326 Mail Service Center

Raleigh, North Carolina 27699-4300

T A B L E O F C O N T E N T S

E X A M I N A T I O N S

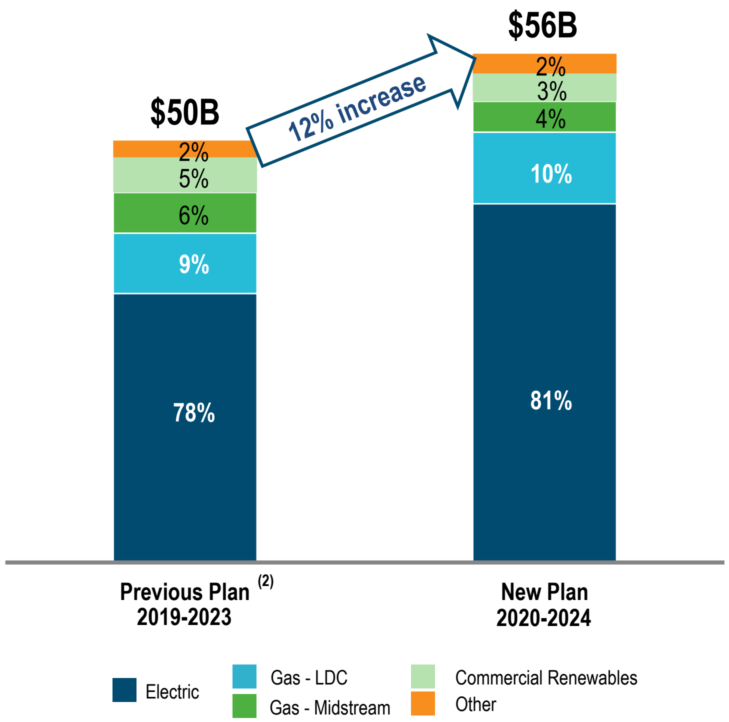
E X H I B I T S


DUKE ENERGY.
Earnings Review
& Business Update
FOURTH QUARTER 2019
Lynn Good Chairman / President and CEO
Steve Young Executive Vice President and CFO
February 13, 2020

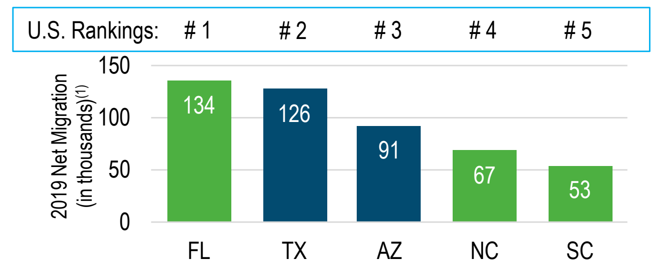
Rapidly expanding infrastructure needs driven by strong fundamental growth

DUKE ENERGY.

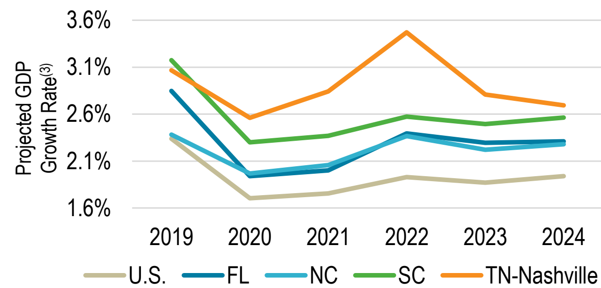
12% INCREASE IN 5-YEAR CAPITAL PLAN; LOW RISK INVESTMENTS



SERVING THREE OF THE MOST VIBRANT STATES IN THE COUNTRY



GDP GROWTH PROJECTIONS ABOVE THE NATIONAL AVERAGE



(1) Source: Wells Fargo Securities; U.S. Department of Commerce
(2) As disclosed in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019
(3) Source: U.S. Bureau of Economic Analysis (BEA); Moody's Analytics Forecasted

VITALITY OF COMMUNITIES DRIVES REGULATED FOCUSED GROWTH

$6B Increase in capital plan drives significant earnings base growth

Florida - $1.5B increase

- Grid hardening supported by Storm Protection Plan regulations (SB 796)
- Solar investments
- Underpinned by highest net migration in the U.S.[1]

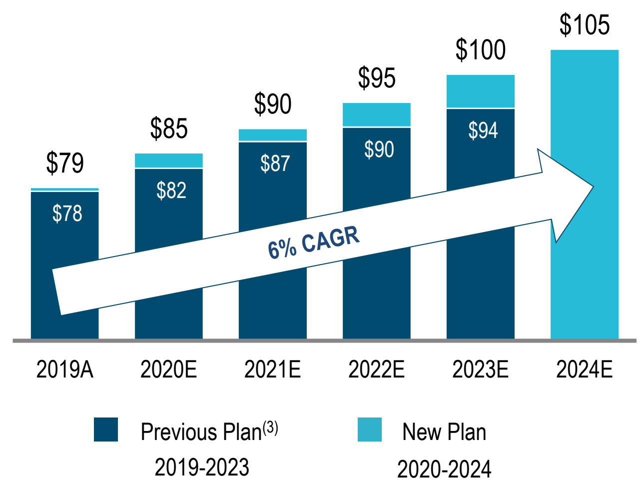
Carolinas - $4B increase

- T&D grid of DEC and DEP represents one of the largest systems in the country
- T&D investment needs driven by migration that ranks 4th (NC) and 5th (SC) in the U.S.[1] and NC solar penetration that ranks 2nd in the U.S.
- Storm hardening and resiliency

Gas LDCs - $1B increase

- Integrity management programs
- Infrastructure to support strong customer growth

REGULATED ELECTRIC AND GAS EARNINGS BASE[2]



(1) Source: Wells Fargo Securities; U.S. Department of Commerce
(2) In billions. Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex - D&A - deferred taxes
(3) As disclosed in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019

STRENGTHENED BALANCE SHEET (BBB+/BAA1 STABLE) UNDERPINS ABILITY TO EXECUTE ON $56B CAPITAL PLAN

Balance sheet strength and equity financing plan

KEY MESSAGES

- Committed to maintaining strong credit quality, including investment-grade ratings
  - Credit ratings recently affirmed at BBB+/Baa1 (Stable)
  - Credit metrics are consistently solid over the planning horizon
- Settlement of ~$2.5 billion equity forward to occur in Dec. 2020
- Expected equity issuances of $500 million per year 2020-2022 via DRIP/ATM programs; will evaluate continuing need for DRIP/ATM programs upon in-service of ACP

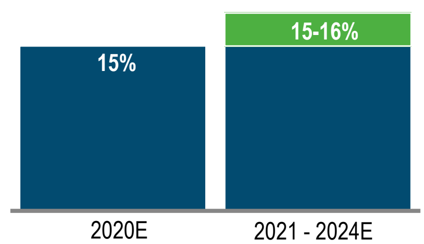
UNIQUE FACTORS CONTRIBUTING TO BALANCE SHEET STRENGTH

- ~$275 million refundable AMT credits expected in 2020
- Not expected to be a significant taxpayer until 2027 timeframe
- Pension plan 107% funded – no contributions forecasted in five-year plan

PRIMARY CREDIT METRICS

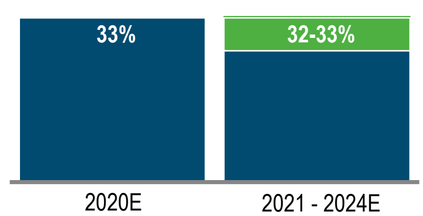
FFO/DEBT

Target: 15 - 16%



HOLDCO DEBT %

Target: Low 30%'s



EQUITY ISSUANCE PLAN REMAINS UNCHANGED FROM 3Q 2019 EARNINGS CALL

Focused on investor value creation

DUK LISTED NYSE

A STRONG LONG-TERM RETURN PROPOSITION

DUK LISTED NYSE

3.9%

DIVIDEND YIELD[1] WITH DIVIDEND **GROWTH COMMITMENT**[2]

~8-10%

ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN**[3]

4-6%

HIGHLY ACHIEVABLE **EPS GROWTH THROUGH 2024**[4]

CONSTRUCTIVE JURISDICTIONS, LOW-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) *As of Feb. 11, 2020*
(2) *Subject to approval by the Board of Directors.*
(3) *Total shareholder return proposition at a constant P/E ratio*
(4) *Based on adjusted EPS off the midpoint of the 2019 guidance range ($5.00)*

DUKE ENERGY PROGRESS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20
ALLETE, Inc.	High Price ($)	88.600	87.830	86.910	82.160	84.710	84.170
	Low Price ($)	83.590	85.130	78.880	78.250	79.400	67.990
	Avg. Price ($)	86.095	86.480	82.895	80.205	82.055	76.080
	Dividend ($)	0.588	0.588	0.588	0.588	0.588	0.618
	Mo. Avg. Div.	2.73%	2.72%	2.83%	2.93%	2.86%	3.25%
	6 mos. Avg.	2.89%					
Alliant Energy Corp.	High Price ($)	54.590	54.430	53.670	55.400	59.740	60.280
	Low Price ($)	50.360	51.580	50.930	52.240	53.320	51.250
	Avg. Price ($)	52.475	53.005	52.300	53.820	56.530	55.765
	Dividend ($)	0.355	0.355	0.355	0.355	0.380	0.380
	Mo. Avg. Div.	2.71%	2.68%	2.72%	2.64%	2.69%	2.73%
	6 mos. Avg.	2.69%					
Ameren Corp.	High Price ($)	80.850	80.050	77.920	77.040	82.410	87.330
	Low Price ($)	73.310	75.260	73.340	73.510	75.540	77.190
	Avg. Price ($)	77.080	77.655	75.630	75.275	78.975	82.260
	Dividend ($)	0.475	0.475	0.475	0.495	0.495	0.495
	Mo. Avg. Div.	2.46%	2.45%	2.51%	2.63%	2.51%	2.41%
	6 mos. Avg.	2.49%					
American Electric Power Co.	High Price ($)	94.890	96.220	94.980	95.770	104.430	104.970
	Low Price ($)	90.080	91.350	88.170	90.210	92.940	86.420
	Avg. Price ($)	92.485	93.785	91.575	92.990	98.685	95.695
	Dividend ($)	0.670	0.670	0.700	0.700	0.700	0.700
	Mo. Avg. Div.	2.90%	2.86%	3.06%	3.01%	2.84%	2.93%
	6 mos. Avg.	2.93%					
Avangrid, Inc.	High Price ($)	52.480	52.238	50.280	52.065	53.940	57.240
	Low Price ($)	49.050	48.250	47.920	48.060	50.210	47.240
	Avg. Price ($)	50.765	50.244	49.100	50.063	52.075	52.240
	Dividend ($)	0.440	0.440	0.440	0.440	0.440	0.440
	Mo. Avg. Div.	3.47%	3.50%	3.58%	3.52%	3.38%	3.37%
	6 mos. Avg.	3.47%					
CMS Energy Corp.	High Price ($)	65.310	65.020	64.140	63.440	68.980	69.170
	Low Price ($)	60.100	62.320	59.330	60.250	61.570	59.120
	Avg. Price ($)	62.705	63.670	61.735	61.845	65.275	64.145
	Dividend ($)	0.383	0.383	0.383	0.383	0.383	0.408
	Mo. Avg. Div.	2.44%	2.40%	2.48%	2.47%	2.34%	2.54%
	6 mos. Avg.	2.45%					

DUKE ENERGY PROGRESS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20
DTE Energy Co.	High Price ($)	134.370	133.390	127.930	130.700	134.720	135.670
	Low Price ($)	127.160	123.410	120.080	123.130	127.620	110.200
	Avg. Price ($)	130.765	128.400	124.005	126.915	131.170	122.935
	Dividend ($)	0.945	0.945	0.945	1.013	1.013	1.013
	Mo. Avg. Div.	2.89%	2.94%	3.05%	3.19%	3.09%	3.29%
	6 mos. Avg.	3.08%					
Evergy, Inc.	High Price ($)	67.810	66.540	65.630	65.150	72.620	76.570
	Low Price ($)	63.350	62.040	62.330	61.970	62.930	63.180
	Avg. Price ($)	65.580	64.290	63.980	63.560	67.775	69.875
	Dividend ($)	0.475	0.475	0.505	0.505	0.505	0.505
	Mo. Avg. Div.	2.90%	2.96%	3.16%	3.18%	2.98%	2.89%
	6 mos. Avg.	3.01%					
Hawaiian Electric Ind.	High Price ($)	45.960	45.780	45.400	47.640	49.630	50.550
	Low Price ($)	43.240	43.970	42.950	43.330	45.040	42.030
	Avg. Price ($)	44.600	44.875	44.175	45.485	47.335	46.290
	Dividend ($)	0.320	0.320	0.320	0.320	0.320	0.330
	Mo. Avg. Div.	2.87%	2.85%	2.90%	2.81%	2.70%	2.85%
	6 mos. Avg.	2.83%					
NextEra Energy, Inc.	High Price ($)	233.450	239.890	238.890	245.010	270.660	283.350
	Low Price ($)	216.370	226.580	220.660	231.070	237.950	243.080
	Avg. Price ($)	224.910	233.235	229.775	238.040	254.305	263.215
	Dividend ($)	1.250	1.250	1.250	1.250	1.250	1.400
	Mo. Avg. Div.	2.22%	2.14%	2.18%	2.10%	1.97%	2.13%
	6 mos. Avg.	2.12%					
Northwestern Corp.	High Price ($)	76.720	76.180	73.340	73.080	77.340	80.520
	Low Price ($)	71.630	70.950	68.030	69.350	69.690	69.490
	Avg. Price ($)	74.175	73.565	70.685	71.215	73.515	75.005
	Dividend ($)	0.575	0.575	0.575	0.575	0.575	0.575
	Mo. Avg. Div.	3.10%	3.13%	3.25%	3.23%	3.13%	3.07%
	6 mos. Avg.	3.15%					
OGE Energy Corp.	High Price ($)	45.770	45.490	43.770	44.550	46.330	46.430
	Low Price ($)	42.410	42.130	41.790	41.830	43.220	37.160
	Avg. Price ($)	44.090	43.810	42.780	43.190	44.775	41.795
	Dividend ($)	0.365	0.388	0.388	0.388	0.388	0.388
	Mo. Avg. Div.	3.31%	3.54%	3.62%	3.59%	3.46%	3.71%
	6 mos. Avg.	3.54%					

DUKE ENERGY PROGRESS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20
Otter Tail Corp.	High Price ($)	55.100	56.690	57.740	53.160	54.300	56.900
	Low Price ($)	50.340	52.560	48.170	48.590	50.830	47.560
	Avg. Price ($)	52.720	54.625	52.955	50.875	52.565	52.230
	Dividend ($)	0.350	0.350	0.350	0.350	0.350	0.370
	Mo. Avg. Div.	2.66%	2.56%	2.64%	2.75%	2.66%	2.83%
	6 mos. Avg.	2.69%					
Pinnacle West Capital Corp.	High Price ($)	98.580	97.520	93.880	90.680	98.810	105.510
	Low Price ($)	91.180	92.060	84.260	84.880	88.100	88.600
	Avg. Price ($)	94.880	94.790	89.070	87.780	93.455	97.055
	Dividend ($)	0.738	0.738	0.783	0.783	0.783	0.783
	Mo. Avg. Div.	3.11%	3.11%	3.51%	3.57%	3.35%	3.22%
	6 mos. Avg.	3.31%					
PNM Resources, Inc.	High Price ($)	52.950	52.980	52.280	51.980	55.240	56.140
	Low Price ($)	48.710	50.330	47.230	47.850	48.520	45.470
	Avg. Price ($)	50.830	51.655	49.755	49.915	51.880	50.805
	Dividend ($)	0.290	0.290	0.290	0.290	0.308	0.308
	Mo. Avg. Div.	2.28%	2.25%	2.33%	2.32%	2.37%	2.42%
	6 mos. Avg.	2.33%					
Portland General Electric Co.	High Price ($)	58.430	57.520	57.920	57.090	61.710	63.080
	Low Price ($)	54.780	55.410	54.240	54.360	54.550	53.270
	Avg. Price ($)	56.605	56.465	56.080	55.725	58.130	58.175
	Dividend ($)	0.385	0.385	0.385	0.385	0.385	0.385
	Mo. Avg. Div.	2.72%	2.73%	2.75%	2.76%	2.65%	2.65%
	6 mos. Avg.	2.71%					
Southern Company	High Price ($)	62.360	62.880	63.290	64.260	71.100	70.780
	Low Price ($)	58.240	60.450	60.380	60.090	62.240	59.070
	Avg. Price ($)	60.300	61.665	61.835	62.175	66.670	64.925
	Dividend ($)	0.620	0.620	0.620	0.620	0.620	0.620
	Mo. Avg. Div.	4.11%	4.02%	4.01%	3.99%	3.72%	3.82%
	6 mos. Avg.	3.95%					
WEC Energy Group, Inc.	High Price ($)	98.190	96.290	94.730	93.430	101.370	103.280
	Low Price ($)	89.020	91.510	86.500	87.410	90.340	90.160
	Avg. Price ($)	93.605	93.900	90.615	90.420	95.855	96.720
	Dividend ($)	0.590	0.590	0.590	0.590	0.590	0.633
	Mo. Avg. Div.	2.52%	2.51%	2.60%	2.61%	2.46%	2.62%
	6 mos. Avg.	2.55%					

DUKE ENERGY PROGRESS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20
Xcel Energy	High Price ($)	66.050	65.140	63.860	64.670	69.620	72.140
	Low Price ($)	62.190	62.180	59.460	60.850	61.970	61.250
	Avg. Price ($)	64.120	63.660	61.660	62.760	65.795	66.695
	Dividend ($)	0.405	0.405	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.53%	2.54%	2.63%	2.58%	2.46%	2.43%
	6 mos. Avg.	2.53%					
Monthly Avg. Dividend Yield		2.84%	2.84%	2.94%	2.94%	2.82%	2.90%
6-month Avg. Dividend Yield		2.88%					

Source: Yahoo! Finance

DUKE ENERGY PROGRESS PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Zacks	(4) Yahoo! Finance
ALLETE, Inc.	5.00%	5.00%	7.00%	7.00%
Alliant Energy Corporation	5.50%	6.50%	5.70%	5.75%
Ameren Corp.	4.50%	6.50%	6.20%	4.60%
American Electric Power Co.	5.50%	4.00%	5.60%	6.05%
Avangrid, Inc.	3.58%	8.50%	7.40%	6.30%
CMS Energy Corporation	7.00%	7.00%	6.00%	7.50%
DTE Energy Company	7.00%	4.50%	6.00%	6.00%
Evergy, Inc.	NMF	NMF	6.50%	6.50%
Hawaiian Electric	3.00%	2.50%	4.30%	3.30%
NextEra Energy, Inc.	10.50%	10.00%	7.70%	7.99%
Northwestern Corporation	4.50%	2.00%	3.10%	3.49%
OGE Energy Corp.	6.50%	6.50%	4.10%	3.50%
Otter Tail Corporation	4.00%	5.00%	9.00%	9.00%
Pinnacle West Capital Corp.	6.00%	4.00%	4.70%	4.62%
PNM Resources, Inc.	7.00%	7.00%	5.80%	6.30%
Portland General Electric Company	6.50%	4.50%	4.90%	4.70%
Southern Company	3.00%	4.00%	4.50%	2.10%
WEC Energy Group	6.00%	6.00%	6.20%	6.23%
Xcel Energy Inc.	6.00%	5.50%	5.70%	6.10%
Average	5.62%	5.50%	5.81%	5.63%
Median	5.75%	5.25%	5.80%	6.05%

Sources: Value Line Investment Survey, December 13, 2019; January 24 and February 14, 2020
Yahoo! Finance and Zacks growth rates retrieved February 25, 2020
Yahoo! Finance growth rates used for Zacks growth rates for ALLETE, Otter Tail
NMF = No meaningful figure

DUKE ENERGY PROGRESS PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Yahoo! Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.88%	2.88%	2.88%	2.88%	2.88%
Average Growth Rate	5.62%	5.50%	5.81%	5.63%	5.64%
Expected Div. Yield	2.96%	2.96%	2.96%	2.96%	2.96%
DCF Return on Equity	***8.58%***	***8.46%***	***8.77%***	***8.59%***	***8.60%***
Method 2:					
Dividend Yield	2.88%	2.88%	2.88%	2.88%	2.88%
Median Growth Rate	5.75%	5.25%	5.80%	6.05%	5.71%
Expected Div. Yield	2.96%	2.96%	2.96%	2.97%	2.96%
DCF Return on Equity	***8.71%***	***8.21%***	***8.76%***	***9.02%***	***8.67%***

DUKE ENERGY PROGRESS PROXY GROUP
Capital Asset Pricing Model Analysis

30-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.53%
2	Risk-free Rate of Return, 30-Year Treasury Bond	
3	Average of Last Six Months	2.19%
4	Risk Premium	
5	(Line 1 minus Line 3)	9.34%
6	Comparison Group Beta	0.56
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.22%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.40%

Duff and Phelps Normalized Risk-free Rate

1	Market Required Return Estimate	11.53%
2	Duff and Phelps Normalized Risk-free Rate	3.00%
3	Risk Premium	
4	(Line 1 minus Line 2)	8.53%
5	Proxy Group Beta	0.56
6	Proxy Group Beta * Risk Premium	
7	(Line 4 * Line 5)	4.76%
8	CAPM Return on Equity	
9	(Line 2 plus Line 7)	7.76%

DUKE ENERGY PROGRESS PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

30 Year Treasury Bond Data

	Avg. Yield
September-19	2.16%
October-19	2.19%
November-19	2.28%
December-19	2.30%
January-20	2.22%
February-20	1.97%
6 month average	2.19%

Source: www.federalreserve.gov

Value Line Market Return Data:

Forecasted Data:	
Value Line Median Growth Rates:	
Earnings	10.50%
Book Value	8.00%
Average	9.25%
Average Dividend Yield	1.05%
Estimated Market Return	10.35%
Value Line Projected 3-5 Yr.	
Median Annual Total Return	12.00%
Average Annual Total Return	13.42%
Average	12.71%
Average of Projected Mkt. Returns	11.53%

Source: Value Line Investment Analyzer, February 25, 2020

Comparison Group Betas:	Value Line
ALLETE, Inc.	0.65
Alliant Energy Corporation	0.60
Ameren Corp.	0.55
American Electric Power Co.	0.55
Avangrid, Inc.	0.40
CMS Energy Corporation	0.50
DTE Energy Company	0.55
Evergy, Inc.	NMF
Hawaiian Electric	0.55
NextEra Energy, Inc.	0.50
Northwestern Corporation	0.60
OGE Energy Corp.	0.75
Otter Tail Corporation	0.70
Pinnacle West Capital Corp.	0.50
PNM Resources, Inc.	0.60
Portland General Electric Company	0.55
Southern Company	0.50
WEC Energy Group	0.50
Xcel Energy Inc.	0.50
Average	0.56

Source: Value Line Investment Survey

DUKE ENERGY PROGRESS PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Arithmetic Mean	Adjusted Arithmetic Mean
CAPM with Current 30-Year Treasury Yield		
Long-Term Annual Return on Stocks	11.90%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.00%	
Historical Market Risk Premium	6.90%	6.14%
Proxy Group Beta, Value Line	0.56	0.56
Beta * Market Premium	3.85%	3.43%
Current 30-Year Treasury Bond Yield	2.19%	2.19%
CAPM Cost of Equity, Value Line Beta	**6.04%**	**5.61%**
CAPM with D&P Normalized Risk-Free Rate		
Historical Market Risk Premium	6.90%	6.14%
Proxy Group Beta, Value Line	0.56	0.56
Beta * Market Premium	3.85%	3.43%
D&P Normalized Risk-Free Rate	3.00%	3.00%
CAPM Cost of Equity, Normalized Risk-Free Rate	**6.85%**	**6.43%**

Source: Duff and Phelps Cost of Capital Navigator
2019 Cost of Capital: Annual U.S. Guidance and Examples, Chapter 2, Exhibit 2.3, Chapter 3, pages 45-47

North Carolina Public Staff
Data Request No. 24
DEP Docket No. E-2, Sub 1219
Item No. 24-4
Page 1 of 1

Request:

4. With reference to page 22, lines 12-15 of Mr. Newlin's testimony, please provide: (1) copies of all studies performed by the Company and or investment bankers that suggests a capital structure of 47% long-term debt and 53% common equity minimizes the weighted average cost of capital; and (2) all source documents, data, and work sheets used in the studies in (1).

Response:

Duke Energy Progress targets stable 'A' level credit ratings on an unsecured basis. The Company has not performed the studies requested, but instead considers both quantitative and qualitative factors in its assessment of capital structure. In his testimony, witness Newlin notes the Company "…believes this proposed capital structure is optimal for DE Progress, as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers." While reducing the equity component would minimize the WACC on paper, it also increases leverage and risk, reduces cash flow, negatively impacts credit quality, and would increase the cost of debt and equity capital. In order to finance operations at favorable rates through all market conditions, the Company must balance risk due to leverage and cost to customers. In the Company's judgment, the proposed 47/53 capital structure supports those ratings, and impacts the quantitative and qualitative analysis performed by Moody's and S&P. Please refer to the Company's credit rating reports, included in PS DR 22-4, for quantitative analysis performed by the rating agencies.

I/A

			North Carolina Retail Operations						
			DE Progress Proposed Return			NC Attorney General Proposed Return			
Line No.	Description	DEP Requested Cap. Structure	Requested Retail Rate Base	Embedded Cost/ Return %	Grossed Up Operating Income	AGO Recommended Cap. Structure	Requested Retail Rate Base	Embedded Cost/ Return %	Grossed Up Operating Income
1	Long-term debt	47.00%	$ 5,104,191	4.15%	$ 211,824	48.50%	$ 5,267,091	4.15%	$ 218,584
2	Common Equity	53.00%	5,755,790	10.30%	$ 774,485	51.50%	5,592,890	9.00%	657,582
3	Total	100.00%	$ 10,859,981		$ 986,309	100.00%	$ 10,859,981		$ 876,166
4	Increased revenue requirement from Duke Energy Progress Cost of Capital								110,143

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
ALLETE, Inc.	High Price ($)	84.710	84.170	77.390	63.350	59.270	64.900
	Low Price ($)	79.400	67.990	50.010	53.290	48.220	51.600
	Avg. Price ($)	82.055	76.080	63.700	58.320	53.745	58.250
	Dividend ($)	0.588	0.618	0.618	0.618	0.618	0.618
	Mo. Avg. Div.	2.86%	3.25%	3.88%	4.24%	4.60%	4.24%
	6 mos. Avg.	3.84%					
Alliant Energy Corp.	High Price ($)	59.740	60.280	58.150	54.450	49.720	52.470
	Low Price ($)	53.320	51.250	37.660	43.610	44.360	46.150
	Avg. Price ($)	56.530	55.765	47.905	49.030	47.040	49.310
	Dividend ($)	0.380	0.380	0.380	0.380	0.380	0.380
	Mo. Avg. Div.	2.69%	2.73%	3.17%	3.10%	3.23%	3.08%
	6 mos. Avg.	3.00%					
Ameren Corp.	High Price ($)	82.410	87.330	87.660	81.250	75.270	77.420
	Low Price ($)	75.540	77.190	58.740	65.900	66.330	67.140
	Avg. Price ($)	78.975	82.260	73.200	73.575	70.800	72.280
	Dividend ($)	0.495	0.495	0.495	0.495	0.495	0.495
	Mo. Avg. Div.	2.51%	2.41%	2.70%	2.69%	2.80%	2.74%
	6 mos. Avg.	2.64%					
American Electric Power Co.	High Price ($)	104.430	104.970	100.650	88.290	85.850	88.120
	Low Price ($)	92.940	86.420	65.140	71.200	76.230	77.150
	Avg. Price ($)	98.685	95.695	82.895	79.745	81.040	82.635
	Dividend ($)	0.700	0.700	0.700	0.700	0.700	0.700
	Mo. Avg. Div.	2.84%	2.93%	3.38%	3.51%	3.46%	3.39%
	6 mos. Avg.	3.25%					
Avista Corp.	High Price ($)	50.910	52.430	53.000	45.760	42.530	40.840
	Low Price ($)	46.180	45.940	32.090	38.780	34.520	33.340
	Avg. Price ($)	48.545	49.185	42.545	42.270	38.525	37.090
	Dividend ($)	0.388	0.405	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	3.20%	3.29%	3.81%	3.83%	4.21%	4.37%
	6 mos. Avg.	3.78%					
Avangrid, Inc.	High Price ($)	53.935	57.240	53.995	46.830	44.610	47.080
	Low Price ($)	50.210	47.240	35.620	39.720	38.780	40.650
	Avg. Price ($)	52.073	52.240	44.807	43.275	41.695	43.865
	Dividend ($)	0.440	0.440	0.440	0.440	0.440	0.440
	Mo. Avg. Div.	3.38%	3.37%	3.93%	4.07%	4.22%	4.01%
	6 mos. Avg.	3.83%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
CMS Energy Corp.	High Price ($)	68.980	69.170	68.990	64.080	58.960	61.190
	Low Price ($)	61.570	59.120	46.030	53.960	52.350	55.800
	Avg. Price ($)	65.275	64.145	57.510	59.020	55.655	58.495
	Dividend ($)	0.383	0.408	0.408	0.408	0.408	0.408
	Mo. Avg. Div.	2.34%	2.54%	2.83%	2.76%	2.93%	2.79%
	6 mos. Avg.	2.70%					
DTE Energy Co.	High Price ($)	134.720	135.670	119.490	113.300	108.730	117.910
	Low Price ($)	127.620	110.200	71.210	85.530	92.390	102.190
	Avg. Price ($)	131.170	122.935	95.350	99.415	100.560	110.050
	Dividend ($)	1.013	1.013	1.013	1.013	1.013	1.013
	Mo. Avg. Div.	3.09%	3.29%	4.25%	4.07%	4.03%	3.68%
	6 mos. Avg.	3.74%					
Evergy, Inc.	High Price ($)	72.620	76.570	73.160	64.700	62.680	65.400
	Low Price ($)	62.930	63.180	42.010	50.640	54.000	57.600
	Avg. Price ($)	67.775	69.875	57.585	57.670	58.340	61.500
	Dividend ($)	0.505	0.505	0.505	0.505	0.505	0.505
	Mo. Avg. Div.	2.98%	2.89%	3.51%	3.50%	3.46%	3.28%
	6 mos. Avg.	3.27%					
Hawaiian Electric Ind.	High Price ($)	49.630	50.550	55.150	46.660	39.920	40.760
	Low Price ($)	45.040	42.030	33.510	38.790	34.930	34.790
	Avg. Price ($)	47.335	46.290	44.330	42.725	37.425	37.775
	Dividend ($)	0.320	0.330	0.330	0.330	0.330	0.330
	Mo. Avg. Div.	2.70%	2.85%	2.98%	3.09%	3.53%	3.49%
	6 mos. Avg.	3.11%					
NextEra Energy, Inc.	High Price ($)	270.660	283.350	282.570	250.870	256.510	262.260
	Low Price ($)	237.950	243.080	174.800	213.040	222.620	233.760
	Avg. Price ($)	254.305	263.215	228.685	231.955	239.565	248.010
	Dividend ($)	1.250	1.400	1.400	1.400	1.400	1.400
	Mo. Avg. Div.	1.97%	2.13%	2.45%	2.41%	2.34%	2.26%
	6 mos. Avg.	2.26%					
Northwestern Corp.	High Price ($)	77.340	80.520	78.080	65.380	61.420	64.170
	Low Price ($)	69.690	69.490	45.060	52.470	52.100	51.000
	Avg. Price ($)	73.515	75.005	61.570	58.925	56.760	57.585
	Dividend ($)	0.575	0.575	0.600	0.600	0.600	0.600
	Mo. Avg. Div.	3.13%	3.07%	3.90%	4.07%	4.23%	4.17%
	6 mos. Avg.	3.76%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
OGE Energy Corp.	High Price ($)	46.330	46.430	40.320	33.770	32.940	34.910
	Low Price ($)	43.220	37.160	23.010	26.370	27.960	29.220
	Avg. Price ($)	44.775	41.795	31.665	30.070	30.450	32.065
	Dividend ($)	0.388	0.388	0.388	0.388	0.388	0.388
	Mo. Avg. Div.	3.46%	3.71%	4.89%	5.15%	5.09%	4.83%
	6 mos. Avg.	4.52%					
Otter Tail Corp.	High Price ($)	54.300	56.900	51.990	48.220	45.080	44.610
	Low Price ($)	50.830	47.560	30.950	41.070	36.700	36.800
	Avg. Price ($)	52.565	52.230	41.470	44.645	40.890	40.705
	Dividend ($)	0.350	0.370	0.370	0.370	0.370	0.370
	Mo. Avg. Div.	2.66%	2.83%	3.57%	3.32%	3.62%	3.64%
	6 mos. Avg.	3.27%					
Pinnacle West Capital Corp.	High Price ($)	98.810	105.510	100.730	84.690	78.670	82.290
	Low Price ($)	88.100	88.600	60.050	67.290	69.560	69.960
	Avg. Price ($)	93.455	97.055	80.390	75.990	74.115	76.125
	Dividend ($)	0.783	0.783	0.783	0.783	0.783	0.783
	Mo. Avg. Div.	3.35%	3.22%	3.89%	4.12%	4.22%	4.11%
	6 mos. Avg.	3.82%					
PNM Resources, Inc.	High Price ($)	55.240	56.140	52.240	46.820	41.380	43.500
	Low Price ($)	48.520	45.470	27.080	35.390	34.240	36.930
	Avg. Price ($)	51.880	50.805	39.660	41.105	37.810	40.215
	Dividend ($)	0.308	0.308	0.308	0.308	0.308	0.308
	Mo. Avg. Div.	2.37%	2.42%	3.10%	2.99%	3.25%	3.06%
	6 mos. Avg.	2.87%					
Portland General Electric Co.	High Price ($)	61.710	63.080	59.810	53.420	47.500	48.730
	Low Price ($)	54.550	53.270	37.830	44.580	39.510	40.200
	Avg. Price ($)	58.130	58.175	48.820	49.000	43.505	44.465
	Dividend ($)	0.385	0.385	0.385	0.385	0.385	0.385
	Mo. Avg. Div.	2.65%	2.65%	3.15%	3.14%	3.54%	3.46%
	6 mos. Avg.	3.10%					
Southern Company	High Price ($)	71.100	70.780	68.560	61.860	57.710	60.470
	Low Price ($)	62.240	59.070	41.960	49.260	51.990	50.400
	Avg. Price ($)	66.670	64.925	55.260	55.560	54.850	55.435
	Dividend ($)	0.620	0.620	0.620	0.620	0.640	0.640
	Mo. Avg. Div.	3.72%	3.82%	4.49%	4.46%	4.67%	4.62%
	6 mos. Avg.	4.30%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
WEC Energy Group, Inc.	High Price ($)	101.370	103.280	109.530	101.000	91.960	95.820
	Low Price ($)	90.340	90.160	68.010	80.560	81.490	83.840
	Avg. Price ($)	95.855	96.720	88.770	90.780	86.725	89.830
	Dividend ($)	0.590	0.633	0.633	0.633	0.633	0.633
	Mo. Avg. Div.	2.46%	2.62%	2.85%	2.79%	2.92%	2.82%
	6 mos. Avg.	2.74%					
Xcel Energy	High Price ($)	69.620	72.140	70.680	67.440	65.310	67.540
	Low Price ($)	61.970	61.250	46.580	56.960	56.070	61.580
	Avg. Price ($)	65.795	66.695	58.630	62.200	60.690	64.560
	Dividend ($)	0.405	0.405	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	2.46%	2.43%	2.93%	2.77%	2.83%	2.66%
	6 mos. Avg.	2.68%					
Monthly Avg. Dividend Yield		2.84%	2.92%	3.48%	3.50%	3.66%	3.54%
6-month Avg. Dividend Yield		3.32%					

Source: Yahoo! Finance

PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Zacks	(4) Yahoo! Finance
ALLETE, Inc.	4.50%	5.50%	7.00%	7.00%
Alliant Energy Corporation	5.50%	6.50%	5.50%	5.30%
Ameren Corp.	5.00%	6.00%	6.80%	5.90%
American Electric Power Co.	5.50%	5.00%	5.80%	5.88%
Avangrid, Inc.	2.50%	6.00%	5.50%	6.40%
Avista Corp.	4.00%	1.00%	5.20%	6.00%
CMS Energy Corporation	7.00%	7.50%	6.90%	7.16%
DTE Energy Company	6.50%	5.00%	5.50%	5.84%
Evergy, Inc.	5.50%	3.00%	5.00%	3.90%
Hawaiian Electric	4.00%	3.50%	1.70%	3.30%
NextEra Energy, Inc.	10.50%	10.00%	7.80%	8.07%
Northwestern Corporation	4.00%	2.50%	3.40%	3.70%
OGE Energy Corp.	6.00%	3.00%	3.70%	2.40%
Otter Tail Corporation	5.00%	3.50%	9.00%	9.00%
Pinnacle West Capital Corp.	5.50%	4.50%	5.20%	4.48%
PNM Resources, Inc.	5.50%	6.00%	6.10%	5.65%
Portland General Electric Company	6.00%	4.00%	5.30%	4.15%
Southern Company	3.00%	3.00%	4.00%	4.52%
WEC Energy Group	6.50%	6.00%	5.90%	5.90%
Xcel Energy Inc.	6.00%	6.00%	5.90%	6.00%
Average	5.40%	4.88%	5.56%	5.53%
Median	5.50%	5.00%	5.50%	5.86%

Sources: Value Line Investment Survey, April 24, May 15, and June 12, 2020
Yahoo! Finance and Zacks growth rates retrieved June 23, 2020
Yahoo! Finance growth rates used for Zacks growth rates for ALLETE, Otter Tail

PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Yahoo! Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.32%	3.32%	3.32%	3.32%	3.32%
Average Growth Rate	5.40%	4.88%	5.56%	5.53%	5.34%
Expected Div. Yield	3.41%	3.41%	3.42%	3.42%	3.41%
DCF Return on Equity	***8.81%***	***8.29%***	***8.98%***	***8.95%***	***8.75%***
Method 2:					
Dividend Yield	3.32%	3.32%	3.32%	3.32%	3.32%
Median Growth Rate	5.50%	5.00%	5.50%	5.86%	5.47%
Expected Div. Yield	3.42%	3.41%	3.42%	3.42%	3.41%
DCF Return on Equity	***8.92%***	***8.41%***	***8.92%***	***9.28%***	***8.88%***

PROXY GROUP
Capital Asset Pricing Model Analysis

30-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.90%
2	Risk-free Rate of Return, 30-Year Treasury Bond	
3	Average of Last Six Months	1.63%
4	Risk Premium	
5	(Line 1 minus Line 3)	10.26%
6	Comparison Group Beta	0.74
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.62%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.25%

Duff and Phelps Normalized Risk-free Rate

1	Market Required Return Estimate	11.90%
2	Duff and Phelps Normalized Risk-free Rate	3.00%
3	Risk Premium	
4	(Line 1 minus Line 2)	8.90%
5	Proxy Group Beta	0.74
6	Proxy Group Beta * Risk Premium	
7	(Line 4 * Line 5)	6.61%
8	CAPM Return on Equity	
9	(Line 2 plus Line 7)	9.61%

PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

30 Year Treasury Bond Data

	Avg. Yield
January-20	2.22%
February-20	1.97%
March-20	1.46%
April-20	1.27%
May-20	1.38%
June-20	1.49%
6 month average	1.63%

Source: www.federalreserve.gov

Value Line Market Return Data:

Forecasted Data:	
Value Line Median Growth Rates:	
Earnings	9.00%
Book Value	6.50%
Average	7.75%
Average Dividend Yield	1.24%
Estimated Market Return	9.04%
Value Line Projected 3-5 Yr.	
Median Annual Total Return	14.00%
Average Annual Total Return	15.51%
Average	14.76%
Average of Projected Mkt. Returns	11.90%

Source: Value Line Investment Analyzer, June 24, 2020

Comparison Group Betas:	Value Line
ALLETE, Inc.	0.85
Alliant Energy Corporation	0.80
Ameren Corp.	0.80
American Electric Power Co.	0.75
Avangrid, Inc.	0.80
Avista Corp.	0.60
CMS Energy Corporation	0.80
DTE Energy Company	0.90
Evergy, Inc.	1.05
Hawaiian Electric	0.55
NextEra Energy, Inc.	0.85
Northwestern Corporation	0.55
OGE Energy Corp.	1.05
Otter Tail Corporation	0.85
Pinnacle West Capital Corp.	0.45
PNM Resources, Inc.	0.50
Portland General Electric Company	0.55
Southern Company	0.90
WEC Energy Group	0.80
Xcel Energy Inc.	0.45
Average	0.74

PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Arithmetic Mean	Adjusted Arithmetic Mean
CAPM with Current 30-Year Treasury Yield		
Long-Term Annual Return on Stocks	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	4.90%	
Historical Market Risk Premium	7.20%	6.14%
Proxy Group Beta, Value Line	0.74	0.74
Beta * Market Premium	5.35%	4.56%
Current 30-Year Treasury Bond Yield	1.63%	1.63%
CAPM Cost of Equity, Value Line Beta	**6.98%**	**6.19%**
CAPM with D&P Normalized Risk-Free Rate		
Historical Market Risk Premium	7.20%	6.14%
Proxy Group Beta, Value Line	0.74	0.74
Beta * Market Premium	5.35%	4.56%
D&P Normalized Risk-Free Rate	3.00%	3.00%
CAPM Cost of Equity, Normalized Risk-Free Rate	**8.35%**	**7.56%**

Source: Duff and Phelps Cost of Capital Navigator
2020 Cost of Capital: Annual U.S. Guidance and Examples, Chapter 2, Exhibit 2.3,
2019 Cost of Capital: Annual U.S. Guidance and Examples, Chapter 3, pages 45-47

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
DOCKET NO. E-7, SUB 1214

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of)
Application of Duke Energy)
Carolinas, LLC for Adjustment)
of Rates and Charges Applicable)
to Electric Service in North)
Carolina)

DEPOSITION OF STEVEN C. HART

Monday, March 2, 2020, 9:30 a.m.
North Carolina Department of Justice
114 Edenton Street
Raleigh, North Carolina

Reported by Susan A. Hurrey, RPR

Worley Reporting
P.O. Box 99169
Raleigh, NC 27624
919-870-8070

APPEARANCES

For Duke Energy Carolinas, LLC:

Kiran H. Mehta, Esq.
Troutman Sanders
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

For the State of North Carolina:

Teresa L. Townsend, Esq.
North Carolina Department of Justice
Consumer Protection Division
114 West Edenton Street
Raleigh, North Carolina 27603

In Attendance:

Michael Kirby, Videographer

EXAMINATION INDEX

EXHIBIT INDEX

VIDEOGRAPHER: We're on the record at 9:30 a.m. This is the deposition of Steven C. Hart. This deposition is being held at North Carolina Department of Justice, 114 West Edenton Street in Raleigh, North Carolina on March 2, 2020. The court reporter is Susan Hurrey. The videographer is Michael Kirby.

Counsel, please introduce themselves and who they represent.

MR. MEHTA: My name is Kiran Mehta. I'm from the Troutman Sanders firm. I represent Duke Energy Carolinas.

MS. TOWNSEND: And I'm Teresa Townsend with the Department of Justice.

VIDEOGRAPHER: Court reporter, please swear in the witness.

STEVEN V. HART

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

DIRECT EXAMINATION BY MR. MEHTA:

Q. Good morning. Just identify yourself for the record, please.

A. My name is Steven with a V, Charles Hart, H-a-r-t.

Q. Are you the same Steven with a V Hart who caused to be prefiled in this docket on about, I think, the 18th of February, written testimony consisting of 128 pages along with multiple exhibits?

A. Yes, I am.

Q. Do you have any corrections to your written testimony?

A. Yes. I have four minor corrections that I'd like to make.

Q. If you would just note the pages and lines, and we'll go from there.

A. Okay. So on page 14, line 16, it should say and corrective action plans and then up to 180 days from submission of groundwater assessment reports, instead of corrective action plans. So the corrective action plans would be due up to 180 days from submission of the groundwater assessment reports, not from the corrective action plans.

Q. So substitute in line 16 groundwater assessment reports for corrective action plans?

A. Correct.

Q. Anything else?

A. Yes. On page 31, line 23 and then starting on line 22, just the sentence starting with because they were installing locations that were, and it should say not

upgrading from other sources of contamination inserting the word not in between the word and upgrading in line 23.
Q. Okay. Anything else?
A. Yes. On page 77 on line 20. The 2L standard for iron is 300 micrograms per liter, not 200. I think that's the only place that I made that error.
Q. Anything else?
A. And then on page 81, line two starting on line one. In 1984 Belews Creek converted to dry ash handling but still had the ability to wet sluice, it should say bottom ash instead of fly ash until 2018. And that's it.
Q. Thank you, Mr. Hart. And the testimony that you filed was on behalf of the attorney general who is the intervener in this case, correct?
A. That's correct.
Q. You are aware, are you not, Mr. Hart, that in Duke Energy Carolinas's previous rate case, docket number E7, sub 1146, and in Duke Energy Progress's previous rate case, which was docket number E2, sub 1142, Dan Wittliff appeared as a witness for the Attorney General and testified in both cases?
A. Are you asking if I was aware of that?
Q. Yes.
A. No.
Q. Did you review any testimony from the previous

cases of Mr. Wittliff?
A. Not Mr. Wittliff, no.
Q. Well, the record will reflect this, Mr. Hart, but in one or perhaps both of those two prior cases, Mr. Wittliff was asked by the chair of the Utilities Commission whether it was his view that whichever utility it was in question, was imprudent when it first sluiced coal ash to impoundments that were unlined?
MS. TOWNSEND: Well, objection. Go ahead and answer.
BY MR. MEHTA:
Q. Are you aware that the chairman of the commission asked Mr. Wittliff that question?
A. I am not, no.
Q. Would you accept, subject to check, that that question was asked?
A. Are you asking me to assume that or do you have something with the testimony that I could look at?
Q. I don't have the paper with me. It's voluminous. I guess in the Utilities Commission parlance, subject to check means I'll accept it, but I reserve the right to check on it later. And obviously if I misstated that question, you can correct it when you review the transcript of your deposition.
MR. MEHTA: Is that acceptable, Counsel?

MS. TOWNSEND: That's acceptable. That is customary in NCUC cases.
THE WITNESS: Okay.
BY MR. MEHTA:
Q. So you would accept, subject to check, that the chairman of the commission did ask that question of Mr. Wittliff?
A. Based upon your representation, yes.
Q. And would you accept, again, subject to check, that Mr. Wittliff's answer to the question of whether the utility was imprudent when it first sluiced ash to an unlined pound was, quote, no, the law allowed them to do it and the law continued to allow them to do it even though there was concern? Would you accept that, subject to check?
A. Yes, subject to your representation, yes.
Q. My question to you, Mr. Hart, is do you agree or disagree with Mr. Wittliff?
A. I haven't formulated an opinion about that.
Q. Is there some reason you have not formulated an opinion about that?
A. It wasn't part of my scope of work. I looked at groundwater contamination associated with the basins.
Q. So the legality of the manner in which Duke Energy Carolinas operated its basins was not part of your

scope?
A. Well, I'm not an attorney, so I can't -- I wouldn't make decisions about whether something was legal or not. Wouldn't be part of my opinion.
Q. Well, Mr. Wittliff is not an attorney either, and he certainly asserted that it was legal.
MS. TOWNSEND: Objection. Go ahead, if you can answer.
THE WITNESS: Well, I'm not Mr. Wittliff. Don't know his basis for that and I haven't formulated an opinion about it, and I'm not an attorney so I wouldn't make a legal conclusion about that.
BY MR. MEHTA:
Q. So then you also would not make any kind of conclusion or have any kind of opinion as to whether the law continues to allow Duke Energy Carolinas and Duke Energy, progress to operate their plants and ash impoundments in that fashion even today with respect to active plants?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Again, I haven't looked into that issue. Again, I'm not making a legal opinion about legal conclusions.
BY MR. MEHTA:
Q. And I take it then that you do not have an

opinion as to whether or not the law will allow continued sluicing of coal ash to unlined pounds until alternate coal ash handling is implemented on the time frame that the law requires?
MS. TOWNSEND: Objection as to form.
THE WITNESS: I haven't looked into the law with regard to that matter.
BY MR. MEHTA:
Q. So you don't have an opinion one way or the other?
MS. TOWNSEND: Objection.
THE WITNESS: Again, I'm not here to make legal conclusions. I have read the CCR rules and CAMA rules and I don't have any reason -- I mean, I believe that there are -- you can still operate or one can still operate some of these basins, yes.
BY MR. MEHTA:
Q. The ones that are associated with active plants, correct?
A. Yes, that's my understanding. But, again, I'm not here to make a conclusion about whether that is legal or not.
Q. Well, in your review of CAMA and the CCR rule, you did not see anything that prohibits this company or any other utility operating an active coal plant from

sluicing coal ash to a surface impoundment that is not lined, did you?
MS. TOWNSEND: Objection as to form.
THE WITNESS: I don't recall what the specific dates were with regard facilities that were out of use or facilities that were still in operation.
BY MR. MEHTA:
Q. The ones that are still in operation have a time frame in which they are supposed to convert from the wet handling of ash to the dry handling of ash, correct?
A. That's my understanding, yes.
Q. As long as they are operating within that time frame, so far as you are aware they're operating legally, correct?
MS. TOWNSEND: Well, objection as to form.
THE WITNESS: I think that is consistent with my reading of the CAMA rules and CCR rules, but again, I'm not here to make a legal conclusion about that.
BY MR. MEHTA:
Q. Mr. Hart, since you haven't read Mr. Wittliff's testimony, you may not be aware, that in his -- in the last rate case he stated on cross-examination that the company should recover its cost to comply with the federal CCR rule.
MS. TOWNSEND: Objection as to form.

BY MR. MEHTA:
Q. Again, you can take that subject to check. I might actually have that.
(Pause.)
Q. We don't need to make this an exhibit because it is an already public-filed document. But I'm going to hand you what I believe is -- there are multiple volumes, but I believe this is volume 11, page 281 of the Duke Energy Carolinas previous rate case E7 sub 1146.
A. Okay.
Q. If you look at lines 14 through 19. Confirm for me that what I just said as to Mr. Wittliff's testimony is accurate.
A. So you're asking me to assume this is from Mr. Wittliff's testimony --
Q. Yes.
A. -- in that case? Okay. I mean, I believe that's what it says, yes. I don't have his whole testimony so -- it may be taken out of context. I don't understand the context. You have handed me one page of at least a 281 page testimony so --
Q. Well, he wasn't the only witness that day.
A. I understand.
Q. I accept your answer for what it is. But assuming that that is Mr. Wittliff's answer, and again,

assuming, subject to check, that's not taken out of context, and you can certainly check the context, applying Mr. Wittliff's answer to the coal ash basin closure costs at issue in this case, do you agree that the company should recover its costs to comply with the CCR rule in this case?
A. I haven't developed an opinion about that.
Q. So you have no opinion as to any specific dollar amount of a disallowance of those costs in this case?
A. My testimony is that if Duke had -- or DEC had paid attention to the groundwater contamination that was evident from the groundwater monitoring they did, which clearly showed concern groundwater issues with the basins, that they should have recognized those issues earlier and had they done so, they would have started the closure process sooner. They should have started the closer process sooner, which includes these items that are part of the CCR rules and CAMA. And then if they had done that because it was a reasonable thing to do, then costs would certainly be less had they started earlier than if they started now or started in 2014 after the Dan River and CAMA came in.
Q. My question, Mr. Hart, was -- and I'll rephrase it -- in dollars, what disallowance of costs do you

contend is appropriate?
A. Well, if you look at the time value of money, but also removing what -- I think you should remove the cost of connecting any person within a half mile radius to an alternate water source would be disallowed. That was clearly an unprecedented move and was a direct result of DEC's lack of looking at receptors and a lack of understanding what background information was and whether wells were contaminated or not. I think that should be disallowed and that comes out to around, I believe, 17 or 18 million. And then also with a time value of money, if they started as early as the late 1980s, I think the cost reduction would be around 190 million. If you say they maybe should have started in the mid-1990s, it can go to 140 million. Mid-2000s, I think it's around 70 or 80 million reduction. And then, you know, somewhere around 2010, just the time value money would be around, I believe, 50 million dollars. So I would say somewhere in the 50 to 180 million dollar range.
Q. When you say time value of money, what are you talking about there?
A. Will, just if you start sooner, the inflation -- inflationary rates cost will go up over time. So the inflation rate has varied over time. It's usually around two or three percent in the time frames we're talking

about. So if you started sooner, things would cost less just from simply from the time value of money.
Q. Where is what you just stated in your written testimony?
A. The specific dollar amounts --
Q. Yes.
A. -- are not. But it's certainly in my testimony that costs would be lower had they started earlier.
Q. Why didn't you include the specific dollar amounts?
A. I just -- I don't know. I just didn't think it was -- I think from my standpoint because of some of the uncertainties associated with those costs, just as the timing, you know, I think -- I did do some of these calculations, but I didn't include them in my testimony.
Q. Are they in your work papers?
A. In my work papers that I -- I mean, they're in my office work papers. They're not in what I -- I don't believe I gave them as part of my records request.
MR. MEHTA: I would like, Ms. Townsend, to see those calculations.
MS. TOWNSEND: I'm sorry, I didn't mean to nod. That's fine. We will get those for you.
BY MR. MEHTA:
Q. Just to make sure I have got it straight. Your

calculations are if work -- we'll get to what work -- had begun in the mid-1980s, the costs would be 190 million dollars less?
A. Late 1980s.
Q. Late 1980s.
A. Late 1980s. Now, I also took out from those costs -- I started out with a cost of, I believe, around 405 million for the coal ash cost. Now, that doesn't include costs related to things -- it's my understanding -- the costs are a little bit hard to decipher in some cases. It doesn't include things like -- that aren't related necessarily to the coal ash basin closure. Things like dry ash conversion or a wastewater -- taking the wastewater streams out of the basins and putting in retention ponds or treatment systems or things like that. So it wouldn't include those costs.
Q. Make sure I understand what you did. What you did is take 400-ish million dollars, which -- is that your understanding of the coal ash costs that are being sought for recovery in this case?
A. Yes, that's my understanding. Yes.
Q. Okay. So you take the 400 million dollars and you basically back it up from the inflation rate or reverse it from the inflation rate in these various time frames and you end up with late 1980s 190 million dollars?

A. Yeah. So from that 405 million dollars, I took out the 17 million dollars for connection of alternate water supplies. And then I also took out the CHARA contract fees, the penalty fees associated with the CHARA contract. Because I don't know how to deal with that in the -- that's not an issue I know how to deal with on a time value of money. That's a contractual issue more than it is a cleanup issue.
Q. So is that included or not included --
A. It's not included.
Q. -- in the 405 million dollars?
A. Well, I subtracted -- from 405 I subtracted the 17 or 18 million for -- I can't remember the exact number -- from the 405 million for the water connections. And then I subtracted out the CHARA contract fees, whatever the contract penalty fees for not meeting how much they were supposed to dispose at Brookhaven or whatever the charge facility was. And I don't remember the number exactly, but I believe it was around 80 million or something like that. And then from that number I did a time value of money calculation based upon different time frames starting with 1989, and then looking at the 1993ish time frame and then mid-2000s and then 2010.
Q. All right. Let me make sure I get the math correct, then. You started with 405 million?

A. Correct.
Q. You backed out -- for ease of reference I'll call it 15 million for the water. I understand it's slightly higher than that. So you're around 390 million at that point.
A. Correct. Yes.
Q. And then you backed out the CHARA contract fees, which let's just say they're 80 million, correct?
A. Correct.
Q. So you then took the balance which is somewhere around 310 million, and in effect present valued that back in 1989?
A. Correct. Just based upon the average rate of inflation from 1989 to 2015.
Q. So your view, which is not reflected in your written testimony but is reflected in whatever work papers that you are referring to, is that had the work started in 1989 it would have cost instead of 310 million, 190 million less than that?
A. Correct. Yeah. I think the number comes out to around 342 million as the number I took from the time value of money. I believe that's the number. Not 310. Just in round numbers.
Q. But the methodology is as I described it?
A. Correct.

Q. Whatever the numbers are will be in your work papers I assume?
A. Yes. Correct.
Q. Is there some reason that you decided not to include that in your written testimony?
A. No. I think -- you know, we had some discussions about it, but just decided not to include it unless it, you know, came up as a particular issue, for example in the deposition.
Q. Let me ask you if you agree with the following statement. Even where some company -- and company means Duke Energy Carolinas in utility parlance since that's the company at issue. Let me start it over. Even where some company actions or omissions appear imprudent, such as the failure to deploy a comprehensive groundwater monitoring system at a much earlier date, quantification of costs directly resulting from the acts or omissions would be speculative.
Do you agree or disagree with that statement?
MS. TOWNSEND: Object to form.
THE WITNESS: Could you repeat that for me, please?
BY MR. MEHTA:
Q. Sure. Even where some company actions or omissions appear imprudent, such as the failure to deploy

a comprehensive groundwater monitoring system at a much earlier date, quantification of costs directly resulting from the acts or omissions would be speculative?
A. I don't know that they would be speculative, in my opinion. Certainly there's some uncertainty in the number, but it's not speculative. If you start it earlier, certainly the costs would be less. Just the time value of money. You can say well, is it somewhere in the range of 50 to 180 million. That's reasonable. I can't say it's exactly 132 million dollars and 86 cents, but I can say it's somewhere in that range. It's not speculative.
Q. So somewhere in the range of 50 to 190 million is based on simply the time value of money calculation that you proposed, depending on whether the work started in 1989 or the work started in 2010?
A. Correct. Well, and taking out the things we already discussed.
Q. Understood. Now, you dated the sort of late 1980s to a specific year, 1989. Is there some reason you picked 1989?
A. That's when some of the earliest groundwater monitoring was done at some of the plants that showed groundwater issues.
Q. Which plants?

A. It was, I believe, Belews Creek and there was another one -- I can't remember which plant off of the top of my head. But there was some groundwater monitoring done at those plants which started in the 1989 time frame that showed issues, that showed concerns.
Q. So is it your testimony that work -- and we'll get to what work means -- should have started at all plants in 1989 or Belews Creek and whichever one that you can't remember?
MS. TOWNSEND: Objection to form.
THE WITNESS: Well, I think that was certainly an early indicator of problems at the plants with groundwater contamination from these coal ash basins. And so I think, you know, you can certainly make the case that if it was at one plant or several plants it certainly would apply to almost all the plants. At least there's a reasonable potential that there was groundwater contamination at all the facilities that were in the same geologic setting in the Piedmont region of North Carolina and South Carolina. And so certainly, you know, that's kind of the, at least starting groundwater investigations time frame. I'm not saying they should have closed the ponds starting in 1989. But the process of looking at the groundwater issues and then identifying the issues and then starting to mitigate those issues. It doesn't have

22

to be through closure. It could be through different mechanisms.
Q. But the 405 million dollars that you started with is closure, is it not?
A. No. I'm saying in that time frame -- I'm just looking at what the costs are in that time frame that this rate case is for. If it had started those -- you know, if you had started much earlier, that process -- because the 405 million dollars isn't for closure of all the basins. There's only a couple basins or three basins that are included in there.
Q. But the 405 million dollars is for closure of those basins, whichever they are, correct?
MS. TOWNSEND: Objection to form.
THE WITNESS: No, there's other costs in there, too. There's groundwater monitoring costs. There's groundwater installation costs. There's a number of other costs.
BY MR. MEHTA:
Q. How much of the 405 million dollars would be the type of groundwater monitoring that you assert should have started at least at Belews Creek in 1989?
A. I don't know.
Q. Have you tried to figure it out?
A. Well, I mean, the bulk of the costs are

23

certainly associated with closure, certainly. But I don't know specifically the amount.
Q. So whatever that amount is for closure, is it your testimony, Mr. Hart, that those costs associated with closure of the ponds should have been begun to be incurred in 1989?
A. No. What I'm saying is they should have started the process of doing these groundwater assessments, they're also including the cost, and that would have started closure much sooner.
Q. When would closure have started much sooner?
A. Well, if you look at how long it took them to start closure from the CAMA rules or -- it's about five years. And so you say well, sometime in -- from 1989 to -- you know, five or six years from that time frame would have started the closure process. And that's consistent with the documents. If you review the documents. You know, they say if we started closure here's -- in the DEC documents they say, you know, we think it's going to take us to the point -- in 2003 they say well, we think we can start closure in a specific facility in 2007 and then it's going to take us four, five years to closure. So, you know, you can't just snap your fingers and close the ponds, right. You have to go through the groundwater assessment to figure out if

24

there's a problem. You have pull out -- you have to convert to dry ash handling. You have to take out the other waste streams. And so there is some time associated with that.
Q. So, Mr. Hart, I guess then my question is should ponds have started to close in 1994, '95 time frame?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Potentially if they had paid attention to the groundwater contamination that was occurring that was evident at some of these facilities in 1989. Potentially. Now, would it have been closure? It could have been something else. It didn't have to be closure necessarily. It could have been removing ash more frequently. It could have been controlling groundwater contamination. Using a groundwater extraction treatment system. I mean, there are different methods. But because those methods may have cost less as well. But I didn't factor that into this analysis. Because the closure, especially the expedited closure of these facilities was precipitated by the Dan River spill.
BY MR. MEHTA:
Q. When you say that you didn't factor in the closure costs, I guess I'm having a hard time understanding how you can say that in the mid-1990s the

25

costs that the company would have incurred in dealing with a groundwater problem, if it existed in the mid-1990s, would be 140 million dollars less than what it incurred currently when a large majority of what it incurred currently actually has to do with closure.
MS. TOWNSEND: Objection as to form.
THE WITNESS: But those costs for closure -- well, there's no more expensive option than full excavation of the material. And in some case, either on-site disposal or off-site disposal, even beneficiation is expensive, building your own 90 million dollar plant for beneficiation is not the most reasonable cost way to deal with the coal ash. So if anything, the costs if they had dealt with it in 1993 might not have involved closure. The cost would have been less. They might have closed it in place. They might have done groundwater extraction. They might have excavated material and put in liners. But all those costs would have been less than the now costs which are much more. I mean, full excavation and closure of ponds is by far the most expensive means to do -- to address the ponds.
BY MR. MEHTA:
Q. But they're required under CAMA and the CCR rule to do -- and the Attorney General's directive to do the full excavation of these ponds less some portion of a

couple of the ponds which the settlement agreement between the Department of Environmental -- the DEQ, Department of Environmental Quality and the company and various environmental intervenors requires, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, the original CAMA rules did not require full excavation of all the ponds. They only required those --
BY MR. MEHTA:
Q. The Department of Environmental Quality has required the full -- at one point in time required the full excavation of all the ponds, correct?
A. Yes.
Q. And a settlement of a dispute that arose from that requirement, full excavation of all the ponds is not required, but full excavation of many of the ponds is required, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Correct. But that wasn't the case in any time before that.
BY MR. MEHTA:
Q. So what would it have cost in mid-1990s to close a pond?
A. I don't know. But it would cost less than it does today.

Q. And you don't know what it would cost in the mid-2000s to close a pond, either, do you?
MS. TOWNSEND: Objection as to form.
THE WITNESS: I mean, there's certainly some -- I believe there's some cost estimates from that time in some of DEC materials. Now, whether it's from the mid-2000s -- I don't know exactly when. They started looking at those costs around that time frame.
BY MR. MEHTA:
Q. Your written testimony does not estimate the cost to DEC of closing ash ponds in the mid-2000s, does it?
A. No. Because -- again, what I looked at was there's no more expensive way than to fully excavate these ponds, and the reason for that is because, you know, they had to do that is because of DEC's delay in implementing these measures and the Dan River spill. And so any costs that they -- let's say they decided to close a pond in 2005, would have been less than it is today. They could have chosen a different methodology that it would have certainly been less.
Q. And if they chose a different methodology and the DEQ said sorry, we don't really like that, we want you to excavate it, they would have to do the work twice, wouldn't they?

A. Well, that's why I started -- I'm not sure I understand your question. Why would they have to do the work twice?
Q. Well, let's say they closed a pond in 2005 and they decided to close it in place. So the ash was still there. And today the DEQ says the ash cannot be still there, excavate it.
A. Well, they haven't had that yet. They certainly --
MS. TOWNSEND: Objection.
BY MR. MEHTA:
Q. They would have done work to close the pond and then had to redo work to close the pond in accordance with what the DEQ required, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: So you're asking me to make an assumption that DEQ is going to ask them to -- even though they haven't to date, ask them to remove ponds that were previously closed in place? DEQ hasn't asked them to do it today. There are many ponds out there that were closed in place at the DEC facilities and DEQ hasn't asked them to remove them yet.
BY MR. MEHTA:
Q. Well, the EPA is currently figuring out what rules would apply to those ponds, correct?

MS. TOWNSEND: Objection.
THE WITNESS: I don't know that. But not on that but DEC doesn't have a problem handling their ash twice anyway. They sluiced it into ponds, then they have to excavate it out and put it in a landfill or something. If they had dry ash conversion a long time ago, they could have taken it straight to a landfill. They were double handling their ash anyway. Now, there's no indication that anyone is going to require them to excavate these close in place ponds which are out there. In fact, some of them have landfills on top of them.
BY MR. MEHTA:
Q. Let me make sure I understand your math. Apart from the time value of money, you have really not made any assessment of the costs or how much it would be less if work were done back in 1989, the mid-90s, the mid-2000s or 2010?
A. Not other than the time value of money and the other things that we talked about pulling out those costs.
Q. Right. Mr. Hart, when were you retained by the Attorney General?
A. I think I had a contract by mid-December 2019, as I recall. Our company did.
Q. What was your assignment?
A. My assignment was to look at the documents that

Deposition of Steven C. Hart

-- both in the public record and then DEC had provided that were on these various websites, the mayoral database, the relativity database. And then evaluate the groundwater -- when groundwater contamination was known associated with these coal ash basins. And what actions, if any, should have been taken that were different than the actions that the DEC took, and if they had taken action sooner, assuming that was reasonable that they should have taken it sooner, what the -- what sort of -- would the cost be lower today than they were at the time when these, you know -- if they should have taken action sooner, would the costs have been lower.
Q. And I take it your response -- and I think you posed the questions in your own testimony -- the answer to the first question was yes, they should have taken action sooner?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Yes, that's my opinion.
BY MR. MEHTA:
Q. And that the second is yes, the costs would be lower, but you don't know how much?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I didn't put a number in my testimony. I have given you some numbers today.
BY MR. MEHTA:

Q. I understand. I'm talking about your testimony, your written prefiled testimony.
A. Correct. I gave some -- I said it would be lower. I didn't give an exact figure in my prefiled testimony, no.
Q. What have you been paid to date for your work on this matter? You meaning Hart Hickman.
A. I believe -- well, we haven't been paid yet, not because --
MS. TOWNSEND: I was going to say, that's a sensitive --
THE WITNESS: Not because of the Department of Justice. We have invoiced them for around $40,000, I believe.
BY MR. MEHTA:
Q. The invoice is through what date?
A. I would say without knowing the exact date sometime late January, early February-ish.
Q. Would it cover the time frame through which your testimony was filed?
A. It may have just been slightly short of when the testimony was filed, but it was probably the week before, I think, is when it went through.
Q. And I mean, since the last date that was covered by that invoice through today, just give me a

ballpark on what you have incurred in costs that you will bill to the Attorney General?
A. I don't know. I haven't really looked at that.
Q. Mr. Hart, have you ever been asked to opine regarding the reasonableness of an entity's historic actions for the purpose of evaluating whether those actions would have been expected to result in environmental harm at the time the activities were taking place?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Could you repeat that? I'm not sure I understand.
BY MR. MEHTA:
Q. Sure. Have you ever been asked to opine regarding the reasonableness of an entity's historic actions for the purpose of evaluating whether those actions would have been expected to result in environmental harm at the time that the activities were taking place?
MS. TOWNSEND: Same objection.
THE WITNESS: I'm not sure I understand the last part of the question. Would you repeat it again?
BY MR. MEHTA:
Q. Well, I'll repeat the whole thing.
A. Okay.

Q. And if necessary, we can break it down a little bit. Have you ever been asked to opine regarding the reasonableness of an entity's historic actions for the purpose of evaluating whether those actions would have been expected to result in environmental harm at the time the activities were taking place?
MS. TOWNSEND: Same objection.
THE WITNESS: I mean, that's certainly one of the things I have done before, yes.
BY MR. MEHTA:
Q. In what context?
A. Well, certainly in some litigation context and certainly in some context of working on groundwater contamination cases. It was, was this a reasonable approach to dealing with the waste and had they done something different with that have resulted in lower costs or less contamination. And that's -- I mean, that sometimes is part of what we're looking at.
Q. Can you give me any specifics of the cases in which that has been an issue in which you have rendered an opinion?
A. I'm trying to think. I can't recall any specifically, but I'm trying to think of some.
Q. We'll probably be here for a while. If one pops to mind, let me know.

A. Yeah, I will. I'm not trying to -- I just can't think of any -- but it's certainly something, you know, we do regularly is look at historical practices of a company and what led to contamination and had they stopped doing it sooner or -- you know, changed their process, you know, sooner then that might have resulted in less contamination. I can give you an example, and this might not exactly answer your question, but we do work at the Occidental Chemical -- former Occidental Chemical facility in Castle Hayne, North Carolina, and they have a residual disposal -- they manufacture chromium chemicals and they have a -- their residual solids from the waste water treatment plant are placed into some quarries and they did notice evidence of some groundwater contamination and dealt with that early on by changing the manner in which they treated their residuals, and then had specific limits that they knew would not leach above certain levels so that they could -- the groundwater contamination would not be any worse. So, I mean, there's a case where you look at it and you say, well, they did the right thing. They saw there was evidence of contamination in around the quarries in their groundwater monitoring. None of the wells were installed at the compliance boundary. They were all installed within the compliance boundary. But there were certainly high enough levels that you could

reasonably predict that it was going to be above the levels at the compliance boundary. So they didn't bother putting wells at the compliance boundary. And then they worked to change their process so that there would be less leeching of these chemicals from the residual solids in the groundwater and then they also implemented a corrective action plan.

Q. What was your role in this example?

A. So right now we're doing the work, the groundwater mediation work at the facility both associated with the quarries and then monitoring associated with that. But also they have a whole plant process area that has groundwater contamination as well.

Q. So this is not part of some litigation?

A. Oh, no, no, no, no.

Q. This is part of your ongoing environmental compliance consulting work?

A. Correct. Yes.

Q. Any other examples that come to mind? Particularly any that allies in litigation where you have been asked to opine about this historic reasonableness?

A. Not that I recall specifically -- not that I remember. You know, I have been doing litigation work for a long time. I can't remember everything. But I don't recall any specifics regarding like that. I mean, I have

done some did you comply with the national contingency plan, that kind of thing, when they were doing their investigation. That didn't necessarily lead to more contamination. But certainly a retrospective on past assessment activities for mediation and were they reasonable and necessary, those kinds of things.

Q. Well, when -- in any situation in which you are performing that kind of historical analysis, would you agree with this statement, it is critical to guard against applying today's knowledge to actions from the past or letting today's knowledge color the interpretation of information available in the past?

MS. TOWNSEND: Objection as to form.

THE WITNESS: I'm sorry, could you repeat that, please?

BY MR. MEHTA:

Q. Sure. Would you agree with the statement it is critical to guard against applying today's knowledge to actions from the past or letting today's knowledge color the interpretation of information available in the past?

MS. TOWNSEND: Same objection.

THE WITNESS: I would generally agree with that. I don't know that it's critical, but I would generally agree with that statement, yes.

BY MR. MEHTA:

Q. Now, you source your testimony regarding historical industry knowledge with a number of documents from the 1980s, the 1990s and the 2000s, right?

A. In what context?

Q. Well, I'm trying to think where they are in the context of your report. But I believe there's a section of the report in which you talk about industry and government publications from the 1980s, 1990s and the 2000s.

A. Correct. Yes.

Q. And as I understand it, the purpose of doing that for -- I say report, it's your testimony, although I suspect it started as a report. Somebody put Qs and As in. But the purpose of doing that was to provide some historical context to the question that you were seeking to answer.

MS. TOWNSEND: Objection as to form.

THE WITNESS: Well, just for the record I came up with the Qs and As. I was told to do that. So it didn't start out as a report. It started out as a Q and A just because I was told that was the form it was to be in.

MR. MEHTA: Well, you're way ahead of the game.

THE WITNESS: But, yes, I -- to answer your question, yes, I mean, the reason for looking back at

those was to look at what kind of the industry knew and the environmental community knew and the regulated community knew about what was known about the concern about groundwater contamination regarding coal ash basin.
BY MR. MEHTA:
Q. And I guess just as an example, I know that one of those documents was the 1988 EPA report to Congress on waste from coal plants, right?
A. Yes, I did look at that. Yes.
Q. And I think it's an exhibit, might be Exhibit-21 to your testimony. Does that ring a bell?
MS. TOWNSEND: Objection to form. Go ahead.
THE WITNESS: Not the specific exhibit number, but I do recall the publication, yes.
BY MR. MEHTA:
Q. Did you read the whole publication? It's like 400 pages.
A. Most of it, yes. I mean, I can't say that I read every page in detail, but I certainly skimmed through the document and read most of it.
Q. What was the EPA's general conclusion regarding management of coal ash at the time?
A. I would have to look at the document itself. I have looked at so many documents. If I had it in front of me I could look at it or -- yes.

Q. You did not include their conclusion in your report, correct? In your testimony. Excuse me.
A. I don't recall.
Q. We can look at -- do you have a copy of your testimony?
A. I didn't bring one with me, but I think Terry has one.
MS. TOWNSEND: I have one for you.
BY MR. MEHTA:
Q. I'll point you to a page where you talk about that particular EPA. It starts on page 51 and it is Exhibit-21.
A. Okay.
Q. Did you discuss whatever conclusion the EPA made with respect to management of coal ash at the time in your testimony?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, I don't know. A lot of cases I didn't say here's what the conclusion was. I just said here's the information that I gleaned out about the report. I mean, if you have the specific document and its conclusion, I would be glad to review it.
BY MR. MEHTA:
Q. I mean, I was just using this as an example. It's 400 pages. I understand it's 400 pages and -- I

guess what I'm trying to do is figure out, help me if you can, how you used these historic documents in terms of fashioning the opinions that you presented in your testimony.
MS. TOWNSEND: Objection.
THE WITNESS: Well, I try to certainly be reasonable and fair about what the document was about. There were certainly some that, you know, indicated that they felt like -- especially some of the early studies -- that there wasn't as much concern about groundwater monitoring -- I mean, groundwater contamination and most of that was because the industry was making claims that it was installing more liners, it was doing more groundwater monitoring. And so, you know, I think at least at that time frame I think EPA had some -- recognizing that these had contamination, but they felt that the industry might take care of it by themselves by doing these things.
BY MR. MEHTA:
Q. Is that what the report reflects?
A. I don't know about that specific report. Like I said, I don't have it in front of me. I would have to look. But certainly I tried to be fair in my review of some of these that said, you know, in some cases -- you know, even the report that was done at the Allen plant, you know, the conclusion from that was that there was

groundwater contamination, but it wasn't migrating very far. And that there was -- you know, they felt like there was significant attenuation capacity in some of the soils below the basins. Now, it turned out to not necessarily be correct, but that was a conclusion at the time.
Q. Are you quarrelling with the conclusion at the time?
A. No. I think over time a lot more data was developed, which is not uncommon.
Q. In fact it's very normal, isn't it?
A. Yes. As more data is collected and that's why, you know, data kept being collected at some of these basins regarding leachate analysis, what impacted fluidized gas, desulfurization. But that -- you know, that doesn't -- just because people are still looking at that issue doesn't mean you can ignore the groundwater data that was being collected at these individual facilities, which showed problems.
Q. You're a geologist by training --
A. Correct.
Q. -- and experience?
A. I mean, I consider myself a hydrogeologist.
Q. A super-specialized geologist.
A. Well, yeah, geologist overall, but specializing in hydrogeology.

Q. I guess the point is, I think you mentioned in your testimony that Hart & Hickman is an environmental consulting and engineering firm, correct?
A. That's correct.
Q. You don't do engineering, do you?
A. Me personally?
Q. Correct.
A. No, I'm not an engineer.
Q. Somebody else, Mr. Hickman perhaps, does the engineering at Hart & Hickman?
A. We have a number of engineers, yes. We work together on projects. I mean, you can't ignore the geology part when you're doing the engineering part if you're dealing with these issues, the contamination issues.
Q. So I take it, Mr. Hart, that you have never designed an ash basin, have you?
A. No.
MS. TOWNSEND: Objection to form.
BY MR. MEHTA:
Q. Have you been to an ash basin?
A. Yes.
Q. An ash basin operated by one Duke -- one or another of the Duke utilities?
A. No.

Q. Which ash basins have you visited?
A. There was one up in Michigan.
Q. What was the purpose of your visit?
A. We have a client that does environmental risk transfers for coal fired power plants. So to take on the environmental liability as well as the, in some cases, demolition liability. And so I accompanied them on the trip to see the facility that actually had a -- you know, it had gotten an award to do that. So I was involved in some of the early planning and environmental investigations and we visited this plant and there were still -- ponds still in existence.
Q. Were they lined or unlined?
A. I believe they were unlined, as I recall. But I don't know specifically.
Q. Do you recall the owner that you were working for?
A. Consumers Energy, I believe. Well, our client had the contract with Consumers Energy.
Q. Right. Consumers probably would have developed -- built, developed and designed the ponds back when it was actually operating as a utility, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: I don't know. They may have hired somebody else. They may have bought this facility

at sometime from someone else. In fact, I think they may have bought it from another utility.
BY MR. MEHTA:
Q. Do you remember how old the ponds were?
A. No. We don't -- our client decided not to -- got the award and decided to do the demolition of the plant and then to deal with any environmental issues around the plant, including any historical fill areas where CCRs had been placed. But decided not to bid on the closure of the plant -- the ponds because of the uncertainty -- too much uncertainty with regard to the contamination associated with it.
Q. When was this visit?
A. I would say in 2018 maybe. Something like that.
Q. Relatively recently?
A. Yes.
Q. What was the nature of the uncertainty that your client is facing?
A. I think it was mostly cost.
Q. What was the basis for cost uncertainty?
A. I think they were -- there was a lot of difference in cost, depending on who did the work. And I think they just felt it wasn't worth their time to go through the costing process and then taking on that

environmental liability because of some of the uncertainties associated with the closure.
Q. Is there anything else you can remember about why they felt uncertainty with respect to the cost?
A. Not specifically. I just -- I think they felt like they probably couldn't be the low bidder and they were probably going to select the low bidder.
Q. Have you ever designed a coal ash landfill?
A. No.
Q. I should remember this from your -- from the bio information, but you have not worked for DEQ or its predecessor named agencies, have you?
MS. TOWNSEND: Objection.
THE WITNESS: Department of Environmental Quality?
MR. MEHTA: Correct.
THE WITNESS: Our company does have some contracts with DEQ, yes.
BY MR. MEHTA:
Q. You personally, Mr. Hart, have never been a DEQ employee?
A. Oh, no. No, I have not.
Q. And Hart & Hickman has been employed by DEQ from time to time?
A. Yes. We have had some contracts with DEQ. I

mean we still do have some.
Q. Have any of those contracts have anything to do with coal ash basins?
A. No.
Q. Have you ever presented expert opinions in a case involving coal ash other than this one?
A. Not specifically coal ash, no.
Q. And I take it apart from the matter up in Michigan that you described earlier, you have never investigated a site where the presence of coal ash was an issue?
A. No, I have. Yes.
Q. You have?
A. Yes.
Q. And where is that?
A. So we are doing work for the town of Chapel Hill where they have a fill area where coal ash was placed historically before they purchased the property and they built their police department on top of it. And so they have been voluntarily addressing the contamination associated with that fill area and we have been doing the groundwater assessment and interim remedial action, we're in the process of doing that now and then helping the town to eventually come up with a program for remediation.
Q. And the -- I take it this is a landfill, not a

pond or a basin?
A. Right. It was a fill area.
Q. Was the ash placed there as part of a structural -- for the purpose of structural fill or was it placed there for disposal purposes?
A. I don't know. It was a former borrow pit where they pulled soil out and then the person that owned it let people -- well, I guess they charged people to put construction demolition debris in there initially and then allowed the rest of it to be filled with coal ash.
Q. And when you say they allowed, the prior owner allowed or the town of Chapel Hill allowed?
A. The prior owner. The town was not aware when they purchased this property that -- this was in the 1980s that this property that they purchased for their police department had coal ash underneath it.
Q. And how long have you been working on this project?
A. I think since 2014 or '15, I believe.
Q. Is there any litigation surrounding this project or is it just a remediation project?
A. There is no litigation that I'm aware of. You want other examples as well?
Q. Yeah, if you have them.
A. So I have also worked for Holy Angels, which is

a nonprofit. It's run by the Belmont Abbey nuns for disadvantaged -- well, handicapped, both children and adults, and they have a camp very close to the Allen plant where coal ash was placed as beneficial fill on their property. I believe it was the largest disposal of coal ash at the time. I believe it's a hundred thousand cubic yards were placed by Duke at this location. And because of the groundwater concerns from the -- with regard to the Dan River spill and those kind of things and they had a water supply well that they used at this camp, they were very concerned that there was groundwater contamination that was in their well that -- and they had been supplying this water to these disadvantaged people that used the camp. So we did do some water supply well sampling, DEC had done some as well, didn't find any groundwater contamination from the water supply well, which was good news. DEQ did go out there and sample because they installed these storm drains -- this was, again, in the -- you know, a ravine, large ravine that was filled in and there were pipes placed in it and -- for storm water because now there's no place for storm water to go. This ravine was now full of coal ash.
And so DEQ did go out there and find that there was some fairly significant surface water, contaminated surface water discharging directly into Lake

Wylie from this location. And I believe they have required or have asked Duke to address this issue. I think Holy Angels is also very concerned that they were going to be held responsible because Duke had, you know, said this is your coal ash and we're going to give it to you and you take title to it. And so they were very concerned that they were going to be responsible for this as a nonprofit with significant liability for it. So we did some of the groundwater sampling. I've reviewed some of the surface water -- water supply well sampling, I have reviewed the groundwater data, as well as the surface water data. I believe, though I don't know, that DEC is working on this surface water issue to stop this discharge into Lake Wylie.
Q. When did this beneficial use occur?
A. I think it -- I mean it was -- it was permitted by the state and, you know, there's hundreds of these all over the state where Duke placed this ash in various locations. I think it happened in the late '80s.
Q. Was there any issue with respect to some violation of a permit whenever the permit was granted?
MS. TOWNSEND: Objection to form.
THE WITNESS: I don't believe so, no. There was a permit and they did place the material there. I think the issue really became concern for groundwater

50

contamination or at least the water supply well. We didn't sample the entire property to see if the groundwater was contaminated. But the primary concern was this leaching of metals from the coal ash that surrounded these storm water pipes that was being carried directly into Lake Wylie.
BY MR. MEHTA:
Q. Any other examples?
A. We are doing work for Castle & Cooke, which is the company that bought the Pillowtex facility in Kannapolis, and they have gotten ground fills agreements for both the plant itself where the North Carolina research campus is now and then also for the what they call the wastewater treatment plant area, which is where they did wastewater treatment, but they also sluiced coal ash from the Pillowtex facility all the way to this wastewater treatment facility, and then they dry handled, they dewatered it and then placed it into a permitted coal ash landfill there. So we have been looking at the groundwater contamination associated with that and potential impact to a creek that runs nearby that's part of the potential redevelopment of that site.
Q. Okay. This would have been an old Cannon Mills or Pillowtex plant from which the coal ash was sluiced to?
A. Correct. Yeah, it was sent to a wastewater

51

treatment plant. They pulled out -- dewatered the sluiced ash and then dry landfilled the -- under permit the coal combustion products that had been pulled out.
Q. Anything else?
A. That's all I can recall.
Q. Apart from this case, have you ever been asked, either in an expert witness capacity or a consultant capacity, to provide an opinion as to the reasonableness and prudence of coal ash storage and management practices?
A. Well, I'm not -- say that again. Sorry.
Q. Other than this case, have you ever been asked, either in an expert witness capacity or in a consultant capacity, to provide an opinion as to the reasonableness and prudence of coal ash storage and management practices?
A. My hesitation is I'm not sure that's what I have done in this case.
Q. So, in other words -- let me withdraw that piece of it. Have you ever been asked, either in your capacity as an expert or as a consultant, to provide an opinion as to the reasonableness and prudence of coal ash storage and management practices?
A. Well, again, I think my hesitation was, you know, what I looked at was the groundwater contamination associated with these and then what steps should have been taken in relation to those. Just like any groundwater

52

contamination issue where you identify groundwater contamination and you have issues what other response actions you should take in relation to those. Including resolving the source of the contamination, remediation, those kind of things. And so just like any facility, you're not going to address the contamination unless you get rid of the source. And the source in this case happens to be, you know, the coal ash products.
Q. So I guess I'm confused. Is the answer to my question that you have or have not provided --
A. Well, not specifically for coal ash products, I guess.
Q. Have you ever designed a closure plan for an unlined coal ash basin?
A. No.
Q. Have you ever advised a client to close an unlined coal ash basin?
A. No.
Q. Again, apart from this case -- and you can tell me I need to withdraw that piece of the question too, but have you ever served as an expert or opined in a report or in testimony that an owner should close an unlined ash basin or should have done so at some earlier point in time?
MS. TOWNSEND: Objection to form.

53

THE WITNESS: You're talking about specifically in the context of testimony or litigation?
BY MR. MEHTA:
Q. Well, we can start there, yes. Testimony or litigation.
A. Not specifically related to coal ash contamination or coal ash ponds.
Q. In what context then are you thinking that you may have provided some kind of an opinion like that?
MS. TOWNSEND: Objection to form.
THE WITNESS: Well, like I said before, this is to me a groundwater contamination issue that was identifiable and then, you know, rules and good practice would say if you have a groundwater contamination issue, then, you know, you have an obligation to evaluate the extent, the magnitude, and address the source of that contamination.
MS. TOWNSEND: About an hour and a half. You about ready for a break?
VIDEOGRAPHER: I've got about eight minutes left, nine minutes.
MS. TOWNSEND: Finish it up, yeah.
MR. MEHTA: Why don't we finish the tape?
BY MR. MEHTA:
Q. You mentioned in response to my previous

question not in the context of coal ash. Have you, in fact, opined on whether an owner of a facility that was unlined should close that facility or should have closed that facility at some point in the past, have you made -- have you rendered such an opinion in a context other than coal ash?

MS. TOWNSEND: Objection as to form.

THE WITNESS: Well, I certainly have been involved with cases where they had not done complete investigations of the source of the contamination or the extent of contamination. And, you know, that they should have done a thorough investigation of that contamination. That's certainly part of some of the testimony I have given in some other cases with regard to the groundwater contamination.

BY MR. MEHTA:

Q. So which cases are you talking about here?

A. I mean, I know I have given some testimony in some of the cases I worked in Arkansas -- and I don't remember -- I have worked on probably 10 litigation cases in Arkansas which maybe five or so have had deposition testimony and I don't remember the specific ones. But where there had not been adequate assessment of the magnitude of the contamination, the extent of the contamination to -- you know, because of that they didn't

have a handle on how far the contamination went out, what properties might be affected and what the remediation might entail. I think I did that in the Shepherd case recently. I think that was in 2018. It was involving an ethanol spill which had been -- a firefighting company had been used extensively so they hadn't done any investigation of PFAS and there was people's water supply wells right next to this area where they had this. So we actually went out and tested and found PFAS contamination of groundwater and of these water supply wells and, you know, they hadn't done any investigation of that.

Q. In the Shepherd case, who was your client?

A. Ms. Shepherd and Mr. -- Larry Shepherd is her brother and Sheila Shepherd is -- and they both had contiguous properties, and the Cruises live across the street and they also had groundwater contamination from -- PFAS.

Q. So your client was the owner of the property that was contaminated by whatever the process was that you described with the PFAS issue?

A. Yes. Yes. And, you know, the responsible party, Eco-Energy, basically said well, we're not going to test for those things, we don't think we have to. And, you know, unfortunately these people had been drinking this PFAS contaminated water and Ms. Cruise had young

children, her husband is a police officer had become disabled. And so even though it wasn't required by DEQ, we went out -- it was the right thing to do. We went out there and tested it and sure enough we found contamination of these people's water supply wells.

Q. Is that litigation still going on?

A. The Shepherd case was settled. We're still -- I guess there's been a settlement, both monetary -- and I don't know the amount, but it required that the company to basically clean up the PFAS contamination to nondetector background levels, the PFAS contamination. And I believe the Cruise matter is still ongoing.

Q. They're two separate matters but the same incident?

A. Yes. Yes. The Cruises have not settled other than some -- as my understanding, some issues with regard to their water supply well, putting a point of entry system -- well, we actually installed an alternate source of water first. Actually installed a tank first because Eco alleged that some of this contamination they felt was background, but when they did their background investigation there was no PFAS in background groundwater.

Q. I'm sorry, the responsible party was Teego?

A. I'm sorry, Eco-Energy, E-c-o dash energy.

VIDEOGRAPHER: We've got about three

minutes.

MR. MEHTA: One more. Try to wrap this up then.

BY MR. MEHTA:

Q. In the course of your work on this case, Mr. Hart, did you speak with anybody from the DEQ?

A. I didn't personally, but we were trying to get files, and so we did speak to some people at DEQ about obtaining files at regional offices with regard to groundwater sampling and reporting that had been done pre -- well, since the start of DEC's groundwater monitoring until CAMA basically. And there was -- they indicated that they felt some of the documents were confidential, even though they later agreed that they weren't. So we did have some discussions with the DEQ folks about these documents and locating the documents and whether they were confidential or not. We did end up getting some documents. I certainly don't think -- I think there's some missing documents, but we got what documents they had.

Q. Your contact and communication with DEQ for purposes of your work in this matter has essentially been to gather documents, correct?

A. Generally, yes, I would say that's correct.

VIDEOGRAPHER: We're off the record at

10:58 a.m.
- - -
(A break was taken.)
- - -
VIDEOGRAPHER: We are back on the record at 11:06 a.m.
BY MR. MEHTA:
Q. Mr. Hart, just before the break I asked you if you had had -- in the course of doing the work that you did for this project, had any contact with somebody at DEQ and you mentioned that you had to have some communication with them in order to gather documents, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Yes, in order to obtain some of the documents that they had, yes.
BY MR. MEHTA:
Q. Same question with respect to the South Carolina equivalent of DEQ, DEQ which as I understand it is called DHEC. Did you have any communication with South Carolina DHEC in connection with the work that you did on this project?
A. We did with the Freedom of Information Act office.
Q. So that was again for the purpose of obtaining records from DHEC?

A. Yes, that's correct.
Q. Did they provide you with records?
A. Some. I suspect that there are many, many more but -- well, I know there are.
Q. And the records that you were seeking from both DEQ and DHEC were monitoring records from monitoring wells? What kind of records?
A. Correspondence, monitoring reports, notes. Any kind of record they had with regard to these facilities, primarily related to groundwater, but we didn't limit it to certain things.
Q. And whatever records that you were able to obtain from either DEQ or DHEC you reflected in the analysis that you made, I assume the site-by-site analysis in your report -- in your testimony?
MS. TOWNSEND: Objection to form.
THE WITNESS: Certainly any documents that we receive we -- that I considered in my testimony, yes.
BY MR. MEHTA:
Q. Well, did you receive monitoring reports from either DEQ or DHEC that you did not rely upon and are not reflected in your testimony?
A. No. No.
Q. Did you, in the course of doing your work on this project, speak with anybody at EPA?

A. No.
Q. In connection with your work on this project and apart from the attorneys for the Attorney General, have you spoken to anyone outside of your firm?
A. I'm sorry, could you repeat that?
Q. Well, aside from somebody that works with you, a colleague at Hart & Hickman and the attorneys for the Attorney General, have you spoken with anybody about the project on which you are testifying today?
MS. TOWNSEND: Objection to form.
THE WITNESS: I mean, in a general sense I have discussed it with some people, yes. I mean, just colleagues or people outside. Like I'm doing some work for the Department of Justice, that kind of thing.
BY MR. MEHTA:
Q. But not the specifics of your conclusions or the manner in which you were going about doing work, that kind of substantive communication?
MS. TOWNSEND: Objection to form.
THE WITNESS: No, not that I can recall.
MR. MEHTA: Mr. Hart, we have been looking at the testimony, prefiled testimony that was filed by the Attorney General, and I think just for purposes of making sure the record is clear, we're going to mark it as an exhibit to your deposition. You're welcome to look at

this one as I ask you questions about it, or if you want to look at the one that your counsel gave you earlier we can certainly do that, but we'll mark it Exhibit-1 for purposes of your deposition.
MS. TOWNSEND: The only thing I note from here, if I'm not mistaken it says confidential and we ended up not making it a confidential document. It is a public record. It's not confidential.
MR. MEHTA: I think as a result of my communication with Ms. Force --
MS. TOWNSEND: Right.
MR. MEHTA: -- we all decided it was not confidential.
MS. TOWNSEND: Right. I just wanted to -- it says confidential on that document. I just want to make sure everyone is clear that it's not a confidential document.
MR. MEHTA: You can put the exhibit sticker on top of the word confidential.
MS. TOWNSEND: That will solve the problem.
(Exhibit-1 marked for identification.)
BY MR. MEHTA:
Q. Now, Mr. Hart, just to confirm, this is a copy of the prefiled testimony that was filed on your behalf

on, I think, the 18th of February?
A. It appears to be, minus the exhibits.
Q. Minus the exhibits.
A. Yes.
Q. And minus the four corrections that you made earlier?
A. Correct. Yes.
Q. Turn, if you would, Mr. Hart, to page five.
A. Okay.
Q. And starting down on the bottom of page five and going on toward -- onto the top of page six, you indicate that your testimony is focusing primarily on answering two questions, is that right?
A. Yes.
Q. The first one deals with prudence of the company's actions to address storage and disposal of CCR, which I take it is the acronym we're all using for coal combustion residuals, and closure of its coal ash basins before the Dan River spill, correct?
MS. TOWNSEND: Objection as to form. Go ahead.
THE WITNESS: Yes, that is the first question.
BY MR. MEHTA:
Q. And the Dan River spill, if memory serves, was

the second of February, 2014. Does that ring a bell with you?
A. Yes, I know it was February 14, yes.
Q. I remember it was Super Bowl Sunday. That's all I remember.
A. Oh, okay.
Q. And the second question is how would the costs that DEC is seeking today for coal ash-related activities likely be different, correct?
A. Yes.
Q. When you say likely be different, what do you mean by likely?
A. Well, two would be in the context of this, it would be more likely than not.
Q. And your answer to these questions is contained in your testimony, correct?
A. Yes. Well, other than we have discussed today about specific costs in the deposition.
Q. Well, when you say specific costs, you were actually talking about a, in effect, reverse present value calculation based on the time value of money, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: For the most part, in addition to taking out some other things.
BY MR. MEHTA:

Q. And the one specific cost that you would take out is the connection to public water?
A. Correct. Yes.
Q. But apart from the connection to public water, when you say specific costs, you're talking about time value of money going back in time to various points in time?
A. Correct.
MS. TOWNSEND: Objection as to form.
BY MR. MEHTA:
Q. Turn, if you would, Mr. Hart, to page eight of your testimony. Well, let me back up for a moment. Still back on those two questions that you posed. Just make sure that I understand. You have no other opinions with respect to those two questions beyond what's in your testimony?
MS. TOWNSEND: Objection as to the form.
MR. MEHTA: Do you?
THE WITNESS: Not other than what's been discussed or will be discussed at today's deposition.
MR. MEHTA: Okay.
THE WITNESS: To the extent that we go somewhere that's not covered here based upon your questioning.
BY MR. MEHTA:

Q. I was just really talking about your testimony. There's nothing else in your testimony that answers these two questions other than whatever is in your testimony?
MS. TOWNSEND: Objection as to form.
THE WITNESS: My testimony is inclusive of the testimony itself.
MR. MEHTA: Okay.
THE WITNESS: The exhibits, you know, the other documents that I looked at, plus my experience.
BY MR. MEHTA:
Q. Let me ask it this way, and you correct me if I'm wrong, but as I understand it, what you tried to do in your testimony is provide a full and complete answer to the questions that you posed to yourself?
A. I mean, in general I would say yes. Now, everything that may have been supportive of my opinion may not be in here just because, as I said in here, I pulled certain select documents to keep this to a reasonable size and also considering the time frame in doing the work. But generally I would say yes, everything is covered.
Q. All right. Now turn to page eight of your testimony. And I'm looking at lines five through seven. Mr. Hart, what conclusion should the reader draw from the finding that you recount in lines five through seven?
A. I'm not sure I understand your question.

You're asking me to -- I'm not sure I understand your question.
Q. Well, let me try it again. You indicate that the utility industry knew about the potential for contamination of groundwater. Paraphrasing. Correct?
A. Yes, as early as the 1980s, yes.
Q. Okay. Well, what did the utility industry do since it knew about this potential?
A. Well, in some cases they performed groundwater monitoring to determine if there was groundwater contamination because there was this potential. In some cases they closed basins and installed new ones with liners.
Q. Which cases did a utility close a basin and install new basins with liners because of the potential for contamination of groundwater in the early 1980s?
A. You asked me what response did the industry take and I said those were some of the things that happened in response to contamination of groundwater.
Q. Okay. So which utility are we talking about?
A. Well, I know even a Duke facility, they had one in, I forget -- Indiana where they had closed a basin. They had one lined basin at a facility in Ohio or Indiana. But certainly there were other ones. If you read the documents it says that -- I think at one point in the

1980s 25 to 30 percent had lined basins and like 35 percent were already doing groundwater monitoring.
Q. Were those lined basins recently constructed lined basins or were they used for purposes of moving ash from an unlined basin to a lined basin?
A. I mean, the documents go into whether they were newer, 19 -- I think they did 1985 to -- time period. Newer or whether they were older basins than that. Some of the newer basins certainly had more liners than some of the old ones, but even some of the old ones had liners.
Q. I guess my question, Mr. Hart, really is you mentioned a specific Duke Energy -- a plant in Ohio, one of the Duke midwestern plants that dealt with a contamination issue by building a new basin with a liner, correct? Or a landfill with a liner?
A. Well, it was a pond, a coal ash pond.
Q. Okay. Do you have any other specific example of a utility that took some action with respect to what you're describing here, their knowledge of the potential for the contamination of groundwater from coal ash basins as early as the 1980s?
A. Well, I mean, if you read the documents it says that there are a number of facilities that were doing groundwater monitoring and were installing liners in response to this concern.

Q. And which documents are you talking about?
A. The documents that are exhibits to my testimony. I don't know the specifics, but there are certainly -- I don't know which ones off the top of my head.
Q. The 1988 EPA document, for example, your Exhibit-21?
A. Could be. I would have to look at it.
Q. Sitting here today, you cannot think of a specific example of a document that describes how a utility responded and reacted to the knowledge about the potential for contamination of groundwater?
A. That's not what I said. I said that there were documents, at least one that -- I can't remember the specific one. I can take the time if you want me to go find it. But, you know, I have looked at 400-plus documents. I had 50-plus exhibits attached to my testimony and I don't recall specifically which one.
Q. Well, that was my question. You don't recall specifically a document, sitting here today, that indicates the manner in which some utility actually responded to the knowledge that you indicate was known as early as the 1980s other than the midwestern Duke plant that we have already discussed?
MS. TOWNSEND: Objection as to form and a

mischaracterization.
THE WITNESS: Yeah, I'm not in a position to memorize every document that I look at so no, I don't -- I know there is a document that discusses it, but I don't recall specifically which one, nor would I think that I should be able to recall specifically which one as I sit here today.
BY MR. MEHTA:
Q. When you say discusses it, what is it that you're talking about?
A. That there were utilities that were performing groundwater monitoring and installing liners in response to the concern about groundwater contamination from coal ash basins.
Q. So apart from the Ohio plant that you discussed, sitting here today you cannot think of a specific utility that did anything in reaction to this knowledge?
MS. TOWNSEND: Objection to form. Asked and answered.
THE WITNESS: Not the specific utility, but there were certainly indications in the reports that utilities were doing -- some of the utilities in the industry were doing that.
BY MR. MEHTA:

70

Q. And you have not estimated cost associated with doing that, whatever that is, correct?
MS. TOWNSEND: Objection to form.
THE WITNESS: What specifically are you talking about? Are you talking about in general or specific to a particular location?
BY MR. MEHTA:
Q. You said that there were some utilities, you cannot remember who, that are reflected in reports that you -- or documents that you have read that were doing something different with coal ash basins as far back as the early 1980s. Did I understand you correctly?
A. Different than whom?
Q. Than Duke Energy Carolinas.
A. Well, I didn't say that in my testimony. I just said there were -- the utility industry knew about the potential for contamination from these and some had instituted as a result of that groundwater monitoring and installation of liners.
Q. So is the appropriate response to the knowledge that you indicate the industry had the installation of groundwater monitoring and the associated work that would go along with groundwater monitoring?
MS. TOWNSEND: Objection to form.
THE WITNESS: I'm not sure I understand your

71

question.
MR. MEHTA: Could you read back the previous answer?
- - -
(The requested portion was read back by the reporter.)
- - -
BY MR. MEHTA:
Q. So would you say then, Mr. Hart, that an appropriate response to the knowledge would be the institution of groundwater monitoring and installation of liners as far back as the early 1980s?
A. Those are some appropriate -- could be some appropriate responses, yes.
Q. Are there other appropriate responses?
A. Certainly.
Q. Such as?
A. Closing the basins, converting to dry ash handling so the basins didn't need to be present, removing other waste streams from the basins so that they were no longer needed.
Q. Do you know what any of those solutions would have cost?
A. In what time frame are you talking about?
Q. Well, I'm talking about the time frame that

72

you're talking about in lines five through seven.
MS. TOWNSEND: Objection to form.
THE WITNESS: I have not looked at that specifically. I mean, I was certainly practicing in the late 1980s and we did groundwater monitoring. But I haven't sat down and figured out exactly what it would cost to do groundwater monitoring at some particular facility at that time frame.
BY MR. MEHTA:
Q. And in terms of closing an ash basin, you don't know actually sitting here today what that would cost, do you?
MS. TOWNSEND: Objection.
THE WITNESS: Again, you're talking about this time frame?
BY MR. MEHTA:
Q. No, I'm talking about today. You certainly, apart from having read estimates that other people have performed, don't know how much it would cost to close a coal ash basin, do you?
A. Well, I think I could certainly reasonably rely on other people's cost estimates. So I feel like I do, yes.
Q. Okay. Do you have an opinion as to what it would have cost back in the early 1980s to close an ash

73

basin?
A. Well, I didn't -- I don't know that I said in the early 1980s. I mean, I did calculate, as I mentioned before, closure costs for basins today that are being used to -- for those costs and then did a time value money evaluation back in 1989.
Q. So would you say that closure costs today for a generic ash pond, that in order to figure out what those costs would have been at some earlier point in time, you simply take what it costs today and do the time value of money calculation?
MS. TOWNSEND: Objection to form.
THE WITNESS: That's a method. You could -- I don't know necessarily how you would go back and go to contractors and say what would you have charged to do this in 1982 or 1989.
BY MR. MEHTA:
Q. It's just not possible to do that, is it?
A. It's possible. I think it would take -- you would have to find somebody. I think there are certainly in some cases, not starting in the late 1980s, but in some cases there are some estimates in the DEC documents later on that have cost estimates in them. Potentially you could recreate it. But it would not be -- it would be difficult.

74

Q. And you didn't attempt to?
A. No. I felt that the costs today that are being expended would be on the high end because of the -- and that going back in time would be -- anything that was done previously would have been probably even less costly. So I think my time value of money calculation are actually probably biased on the low side because back then maybe they didn't have to -- they could have closed the place or demonstrated that it would be less impact with in-place closure, or been able to construct a different on-site land fill, didn't have to send it off site or something like that.
Q. Any other thoughts, opinions -- or do you have any other thoughts and opinions with respect to costs associated with the potential contamination of groundwater known by the industry?
MS. TOWNSEND: Objection to form.
THE WITNESS: I'm not sure I understand your question.
BY MR. MEHTA:
Q. I just want to make sure that there's nothing else that you have to say on the subject of costs with respect to the potential for contamination of groundwater from coal ash basins that the industry had knowledge of as early as the 1980s?

75

A. I mean, what's reflected in my testimony, including what we discussed here today, is -- again, I'm not sure how I can answer your question. I don't really understand it.
Q. And when you say what we discussed here today, you're talking about the time value of money --
A. Yes. Yes. I'm sorry.
Q. -- analysis? When did you perform that analysis?
A. Most of it was done -- well, I did -- before my testimony was submitted I did some calculations probably, you know, a week or so before my testimony was filed and then did some after my testimony was filed. Some different dates.
Q. Why did you do it after your testimony was filed?
A. It was something that the DOJ asked me to do to look at different -- to look at the time value of money over different dates.
Q. When did they ask you to do it?
A. Last week, I believe.
Q. Trying to think. Today is the 2nd of March. So somewhere in that last week in February, correct?
A. Correct.
Q. Had you discussed with the DOJ before last week

76

the time value of money work that you had performed prior to the filing of your testimony?
A. Yes.
Q. Did you tell them you didn't want to put it in your testimony?
MS. TOWNSEND: Object as to form.
THE WITNESS: No.
BY MR. MEHTA:
Q. Did they tell you not to put it in your testimony?
MS. TOWNSEND: Object as to form.
THE WITNESS: I mean, we did discuss before the testimony was filed about whether we wanted to include specific costs or not.
BY MR. MEHTA:
Q. Why did you not include specific costs?
MS. TOWNSEND: Object as to form.
THE WITNESS: I think it -- we just discussed that at that time it might be appropriate to leave it open-ended.
BY MR. MEHTA:
Q. Why was it appropriate to leave it open-ended?
MS. TOWNSEND: Objection as to form and also we're getting close to attorney/client privilege here.
THE WITNESS: It was just discussions we had

77

with regard to the testimony.
BY MR. MEHTA:
Q. Did somebody direct you to leave it open-ended or was that something that you decided to do?
MS. TOWNSEND: Object. Attorney/client privilege on that one.
BY MR. MEHTA:
Q. Is it something you decided to do?
MS. TOWNSEND: Objection. Same.
THE WITNESS: I mean, to me it was a joint decision.
BY MR. MEHTA:
Q. Apart from divulging some attorney/client -- actually it's work product confidence you can't tell me why? And I don't want you to divulge any work product confidence.
MS. TOWNSEND: Thank you.
THE WITNESS: Why what? I'm sorry.
BY MR. MEHTA:
Q. Why the joint decision to not include it in your testimony was made?
MS. TOWNSEND: Objection as to form.
THE WITNESS: It was just a decision we made jointly to not include a specific amount at that time.
BY MR. MEHTA:

78

Q. So look -- I guess we're still on page eight of your testimony, Mr. Hart. Lines eight through 10. And you indicate that groundwater monitoring had been conducted as early as the early 1990s at various DEC facilities. Correct?
A. Correct.
Q. So what, if anything, should Duke Energy Carolinas have done at that time with this finding?
A. Well, in my opinion they should have noted that there were groundwater contamination issues around the basins where they had done the monitoring and conducted further assessment to evaluate the extent and magnitude of contamination. And then if it was at these facilities I think it's reasonable to conclude that it may be present at other facilities and that it would be prudent to go do monitoring at some of these other facilities as well where there was coal ash basins to determine whether the water had been affected at those locations as well.
MR. MEHTA: Could you read back that answer, please.
- - -
(The requested portion was read back by the reporter.)
- - -
BY MR. MEHTA:

79

Q. When you say DEC should have noted it, I mean, to whom?
A. Well, they should have noted it themselves and then also brought it to the attention of DEQ or predecessor to DEQ.
Q. Is it your testimony that they didn't note it themselves?
A. I don't know whether they did or not.
Q. Is it your testimony that they did not bring it to the attention of DEQ?
A. I haven't seen any indication that they brought it to the attention of DEQ other than just submitting data.
Q. But you know they submitted data, correct?
A. Well, I haven't seen -- the earliest data submittals that I have seen are from the 2009 time frame, I believe. I tried to get more historical data. To say when they submit it I can't -- could not locate it. Not saying that they didn't, but I can't -- don't have any evidence that they did.
Q. Do you have any evidence that they did not?
A. No.
Q. Do you have any reason to believe that they did not?
A. I don't have any reason to believe they did not

80

send in the data, no.
Q. Should Duke Energy Carolinas, as early as the early 1990s, have closed any ash ponds?
A. In response to what?
Q. In response to the indication of groundwater contamination that you reference at lines eight through 10 on page eight of your testimony?
MS. TOWNSEND: Objection to the form.
THE WITNESS: I mean, they shouldn't have just immediately closed them. They should have done an investigation to determine what the magnitude and extent of the groundwater contamination was and then done an evaluation of what the source, and is there a way to control the source or do something different. But they -- you know, they wouldn't run out without confirmation of groundwater contamination and maybe several years of monitoring, including some downgrading monitoring to find out were these ponds an issue or not.
BY MR. MEHTA:
Q. When you say groundwater contamination, what contaminants are you talking about in lines eight through 10 on page eight?
A. I would have to go back and look specifically. I know there was iron, manganese, there were some other metals as well, chromium, I think, there were some issues

81

with. I would have to go back and look specifically at each facility to determine what was known in the early 1990s, what specific metals or other inorganics like sulfate or TDS or...
Q. What locations are we talking about in lines eight through 10 on page eight?
A. Reference my report. Well, Allen, they did groundwater investigation, you know, as early as 1984 as part of that study and did identify groundwater contamination at the basins. They didn't do anything in response to that. But they -- until 2004 they installed some wells as part of the USWAG pond. At Belews Creek they did groundwater monitoring starting in 1989 as part of the landfill, but some of those wells were within or very near to the ash basin or within the compliance boundary or very near the ash basin, which showed higher levels of contamination than the ones near the river -- I mean near the landfill. Sorry. I know at Dan River they did monitoring starting in, I believe it was 1993. Yes. Did monitoring at Dan River in 1993. 1989 at Marshall for the landfills, but also had some wells close to the ash basin boundaries. And I believe at W.S. Lee they also started groundwater monitoring 1993.
Q. So when you say as early as the early 1990s at some DEC facilities groundwater monitoring had been

conducted, are we talking about Dan River and W.S. Lee?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, there were also the facilities that started earlier. They were doing monitoring in the early 1990s as well.
BY MR. MEHTA:
Q. Well, something earlier than the 19 -- early 1990s would not be, quote, as early as the early 1990s, would it?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, I mean, if they're doing monitoring in the early 1990s then it is they're doing monitoring in the early 1990s. They have may have done it before, but they were doing --
BY MR. MEHTA:
Q. All I'm trying to figure out, Mr. Hart, is what DEC facilities you are referring to in which groundwater monitoring had been conducted as early as the early 1990s. And based on your previous answer, the only two that I could discern in which groundwater monitoring was being conducted in the early 1990s were Dan River and W.S. Lee. Am I wrong?
MS. TOWNSEND: Objection as to form.
THE WITNESS: There were others that were doing groundwater monitoring in the early 1990s as well.

Some that started in 1989. They were still doing groundwater monitoring in 1993.
BY MR. MEHTA:
Q. So at the Allen plant they were still doing groundwater monitoring, so far as you know in the early 1990s?
A. Yes.
Q. So are you saying then that whatever was done in the mid '80s at the Allen plant continued on into the early 1990s?
A. No. I'm saying is they sampled in 1984 as part of the EPA investigation several facilities across the country to evaluate groundwater contamination associated with coal ash basin. One of them was the Allen plant. And they did investigation in several years, '81 to '84 or '81 to '83 and then came out with the report in '84 and it showed groundwater contamination below the basins, but not extending downgrade from the basins. And there was no additional monitoring done again at Allen, I believe, until 2004.
Q. You just said, if I understood you correctly, that some of the plants at which they had been monitoring in the late '80s continued to do monitoring in the early '90s. I'm just trying to figure out which plants.
MS. TOWNSEND: Objection, form.

THE WITNESS: Yes. They would have been just the ones I mentioned just a second ago, except for Allen because they weren't monitoring in the late 1980s.
BY MR. MEHTA:
Q. So Belews Creek?
A. Yes, they started monitoring in 1989 for the landfill. And one of those wells was in the ash basin compliance boundary, next to the ash basin.
Q. Marshall?
A. I just want to get it right so I'm just double-checking. Yes, 1989 monitoring -- groundwater monitoring started at Marshall for some landfills that were also located -- the wells were also located in the ash basin boundary.
Q. So apart from noting groundwater contamination issues and conducting further assessment, as of the early 1990s what should Duke Energy Carolinas have done with respect to any of its ash basins?
MS. TOWNSEND: Objection as to form.
THE WITNESS: I mean, from a groundwater contamination standpoint I think that was what I would consider reasonable at the time. I can't speak for other issues regarding their basin, whether the dam stability or any of those things. I'm looking here at groundwater contamination.

BY MR. MEHTA:
Q. And you can't speak as to whether they should have closed any basin in the early 1990s, can you?
MS. TOWNSEND: Objection as to form.
THE WITNESS: There may have been other reasons, but I think at that time the beginning to learn about the groundwater contamination issues at these facilities wouldn't immediately go and close them at that time, no.
BY MR. MEHTA:
Q. So in the early 19 -- when you say early 1990s, what are we talking about? Up to 1994?
A. Well, I think 1993, 1994 time frame, yes.
Q. And 1993 is when the Dan River and W.S. Lee ground water monitoring programs began, correct?
A. For -- well, Dan River, yes. Yes. Yes, that's correct.
Q. It was part of, as I understand it, you can correct me if I'm wrong, part of a renewal of the facilities NPDES permit that a groundwater monitoring requirement was imposed by DEQ, correct?
A. I believe that's correct yes.
MS. TOWNSEND: Object to form.
BY MR. MEHTA:
Q. Look at lines 11 through 15 on page eight, Mr.

Hart.
A. Okay.
Q. There's a word their in there, their assessment of environmental impact. It's on line 13.
A. Yes.
Q. Is it their EPA?
A. Yes. Their assessments of environmental impact, yes.
Q. And when you say by the early 2000s, by analogy I'm assuming you mean 2003, 2004 time period, correct?
A. Well, I mean, early is probably from 2002, 2003 or four roughly.
Q. By that time. So no later than 2004, let's say?
A. I mean, I was -- yes, I would say so, yes.
Q. So no later than 2004 the industry, as a result of the EPA assessment or determination that you describe, should have been knowledgeable that there would be potential closure of ash basins, correct?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Yes. Yes.
BY MR. MEHTA:
Q. And you include Duke Energy Carolinas in your assessment of the industry and its response, correct?
A. Yes. I think, you know, in some of the 2003

documents the plant retirement even ash basin closure is discussed in those. So that would be consistent with that, yes, time frame.
Q. When you say a 2003 document, you're talking about an internal Duke Energy Carolinas document?
A. Yes. I think there's a 10-year plan from 2003 that includes cost to assess. I believe there were some costs potentially for closure of basins.
Q. Well, is it your testimony that no later than 2004 Duke Energy Carolinas should have acted to close any ash basins?
MS. TOWNSEND: Objection as to form.
THE WITNESS: I think they should have started the process of looking at the -- by that time frame and it's reflected in what their documents indicate, that they should consider dry ash conversions which were -- one of the early steps in the closure of basins and look at how are we going to reduce the liabilities and risks associated with these ponds because of the increased concerns from the environmental community about these and that -- but to do that, what their documents say would have taken some more money upfront and would have overall lessened those liabilities down the road.
BY MR. MEHTA:
Q. How much more money upfront?

A. I'm sorry, I don't understand your question.
Q. You said it would have taken more money upfront. My question is how much more money upfront?
A. I don't know specifically. I mean they do say, you know, to convert some of the plants to dry ash conversion was around 11 to, I think, 35 million with plants that hadn't been converted already. There's a cost in there for about two million, I believe, to have alternate locations for the wastewater streams to be routed to. Some of the indications in some of the documents in 2003.
Q. And you're speaking of the 10-year plan when you say the 2003 document, is that correct?
A. Yes. Yes. There are some cost estimates in there for some of those items, for dry ash conversion, dealing with the wastewater streams that are going in the basins.
Q. So is it your testimony that the company should have spent the money in 2000 or by 2004 to start the process and complete the process of converting the dry ash handling at its plants?
MS. TOWNSEND: Objection as to form.
THE WITNESS: They should have been looking at ways to reduce the impact to groundwater by that time frame. At the facilities where they knew groundwater

contamination was, of course they should have done monitoring by that time as well at these other facilities, which they didn't start until, you know, some cases 2008 because they had indications in these facilities that there were concerns. But that is certainly a potential -- something they could have done at the time, yes.
BY MR. MEHTA:
Q. You mentioned that in the 2003 document, the 10-year plan, there were cost estimates for performing the work that you say they should be doing. So weren't they looking at performing that work in 2003?
MS. TOWNSEND: Objection as to form.
THE WITNESS: They were. But they didn't do anything about it until 2014 after CAMA.
BY MR. MEHTA:
Q. But is it your testimony that they should have been doing something beyond looking as of 2004?
A. Yes, they should have been responding to the groundwater contamination issue at these facilities to decide what steps they needed to take to reduce the impact of these basins. Now, that could include dry ash handling, but there could have been other solutions as well, like closure of basins, putting in a liner, those type of things.
Q. Well, maybe my question was not precise enough.

90

Try it again. Is it your testimony that as of 2004 Duke Energy Carolinas should have gone beyond looking at the issue of closing ash basins and actually closing ash basins?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Not -- I don't think -- well, it certainly is possible that in some cases where they had, you know, issues related to groundwater contamination that had been confirmed that that could have been a step. But they should have been -- yes, they should have been planning and doing an evaluation of what are we going to do about these groundwater contamination issues and looking at implementing those to resolve the groundwater contamination issues.
BY MR. MEHTA:
Q. I think you testified that -- let's just pick the Dan River plant, where groundwater monitoring was instituted in 1993.
A. Correct.
Q. So as of 2004, is it your testimony that the monitoring data that Duke Energy Carolinas gathered and submitted to DEQ suggested that there was groundwater contamination associated with the Dan River coal ash basins?
MS. TOWNSEND: Objection as to form.

91

THE WITNESS: Yes.
BY MR. MEHTA:
Q. Should Duke Energy Carolinas have closed, in your opinion, as of 2004 the Dan River coal ash basins?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, they should have done something to address the groundwater contamination.
BY MR. MEHTA:
Q. My question to you, Mr. Hart, is should they have closed the basin?
A. I think in the case of Dan River where they had by the early 2000s 10 years worth of data showing groundwater contamination, that would have been a reasonable step to take.
Q. Should they have closed the basin?
A. I'm answering your question. It was a reasonable step to take.
Q. Well, were there other reasonable steps to take?
MS. TOWNSEND: Objection. Asked and answered.
THE WITNESS: Potentially, yes.
BY MR. MEHTA:
Q. Such as?
MS. TOWNSEND: Objection.

92

THE WITNESS: Installing a liner. They could have pumped groundwater to --
BY MR. MEHTA:
Q. When you say installing a liner, you mean retrofitting the existing basin so as to install a liner into the existing basin?
A. Yes.
Q. Okay.
A. They could have controlled the groundwater contamination by using groundwater extraction methods. They could have removed ash more frequently. They could have closed the basin as we discussed. They could have lowered the water levels in the basin. They could have started removing water flows, additional water flows from the basin.
Q. When you say remove additional water flows, what do you mean?
A. Well, the storm water that was going in the ponds, the low volume waste, you know, because that was a source of hydraulic loading, you know, that would have been a reasonable step to get out some of these other water sources from the ponds to help lower the hydraulic head of the pond. You know, they raised the dam on these things like 10 feet at Dan River so that substantially increased the hydraulic head, you know, at sometime in the

93

past.
Q. When did they do that?
A. I don't have a specific date. But it was maybe '50s or '70s. I can't remember.
Q. So should they have lowered the 10 feet that they added?
A. Well, they could have lowered the water level. In fact, they did that, I believe, at Belews Creek because of some issues they were having with compliance. Well, I think there were some -- I can't remember. Dam stability issues or something that actually lowered the water level. They weren't operating it at full capacity.
Q. At Belews Creek?
A. I believe it was Belews Creek.
Q. Is that a decision they made with the DEQ?
A. I don't know.
Q. Any other reasonable solutions that come to mind as of 2004 for the Dan River ponds?
A. I mean, that's all I can think of right now.
Q. So close the basin. What would that cost, basins, at Dan River?
MS. TOWNSEND: Objection as to form.
THE WITNESS: At what time?
MR. MEHTA: 2004.
THE WITNESS: I mean, I don't know

94

specifically. I mean, there are -- well, I don't know if there's any estimates or not for Dan River at that time.
BY MR. MEHTA:
Q. To refit the ponds and put a liner in them, what would that have cost?
A. I don't know at that time.
Q. To remove ash more frequently from the ponds, what would that cost?
A. I don't know.
Q. Where would the ash go that's being removed more frequently from the ponds?
A. It could go to an onsite landfill which I believe they had. It could go offsite. In a lot of cases they just dry stack this material. Didn't do much with it, quite frankly. They just dry stacked it.
Q. In a lined area?
A. In some cases. In some cases it was outside. Well, it was not lined, no. It was inside the compliance boundary. My understanding it wasn't in a lined area. In fact, there's reference in some of the documents that they should stop the practice of dry stacking outside the basins.
Q. What would any of those activities, dry stacking in a landfill, taking it offsite to another landfill, what would those activities have cost?

95

MS. TOWNSEND: Objection to form.
THE WITNESS: I mean, I don't know specifically without going, you know, looking at what kind of per ton cost back in the 1990s were common. They certainly had a landfill, I believe, at that time onsite. Could be wrong. But I believe they had a landfill onsite.
BY MR. MEHTA:
Q. Dan River did?
A. I believe so.
Q. And you said remove additional water flows to the pond, ponds. What would that have cost?
A. I mean, I think the documentation shows about two million dollars in 2003 --
Q. What would it have cost at Dan River to do that?
A. They said it's about two million dollars per facility is what the 2003 documents say.
Q. And in connection with closing a pond, they would have to do something with the ash that was generated by the plant, correct?
MS. TOWNSEND: Objection to form.
THE WITNESS: Yes.
BY MR. MEHTA:
Q. What should they have done with the ash that was generated from burning coal to generate electricity if

96

they had closed the pond?
MS. TOWNSEND: Objection to form.
THE WITNESS: It would have been a dry ash handling, which they had already implemented at several facilities.
BY MR. MEHTA:
Q. Bottom ash, dry -- bottom ash handling at several facilities?
A. Well, they had done dry ash and I think the reason that they didn't do bottom ash because they would lose their Bevill exclusion for hazardous waste. And so they continued to sluice bottom ash to these ponds even though they really had -- they could have converted the dry ash but they would have lost their Bevill amendment exclusion if they did that.
Q. I'm sorry, what does that mean in English?
A. What does it mean? It means that in the Bevill amendment, coal-fired power plants could dispose of low volume waste as long as they were co-managed with high volume waste like ash and they would not have to -- they were exempt for hazardous waste determination. So you could actually -- because the Bevill amendment excluded these low volume waste, they could have had hazardous waste going to the basin but would have been hazardous waste had it not been for the Bevill amendment.

97

Q. So in other words, had it not been mixed with the high volume sluice water?
A. Correct.
Q. So if they had converted to dry ash handling, is it your testimony that this low volume but hazardous waste would then have to be treated as hazardous waste?
A. Well, I don't know if it was hazardous waste. They didn't do any -- wouldn't do testing because they didn't necessarily have to. There is indications in some of the documents that they were concerned that it could be a hazardous waste. But yes, you would have to treat those wastes separately or manage them separately to be discharged to serve as water or go through a wastewater treatment plant or something like that.
Q. What would that cost?
A. Well, that's the cost that there's an estimate of two million dollars to convert facilities --
Q. No, Mr. Hart, what would it cost to handle the low volume waste as hazardous waste?
A. I don't know. I don't know if it was hazardous waste.
Q. You mentioned that there was a concern that somebody had presumably at Duke, that if you went to dry ash handling of bottom ash, they might conceivably lose the benefit of the Bevill amendment, correct?

A. Correct.
MS. TOWNSEND: Objection as to form.
BY MR. MEHTA:
Q. If they had gone to dry ash handling and lost the benefit of the Bevill amendment, what would it have cost to deal with the now classified hazardous waste?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, I mean, it didn't necessarily have to be classified as hazardous waste if you treated it and dispose it through an NPDES permit it would not have to be treated as a hazardous waste necessarily.
BY MR. MEHTA:
Q. Which is what they were doing, right?
A. Except they were putting in ponds for dilution.
Q. So would they have to construct a new pond?
MS. TOWNSEND: Objection to form.
THE WITNESS: Potentially, yes. Or a wastewater plant or something like that.
BY MR. MEHTA:
Q. And what would that cost?
A. I don't know. I mean, like I said, there was an estimate of two million dollars to convert -- to get these other waste streams out of the pond.
Q. But you would still have to deal with them,

correct?
MS. TOWNSEND: Objection to form.
THE WITNESS: Yes, you would have to.
BY MR. MEHTA:
Q. So somebody would have to construct something, some new landfill, new pond, you know, treat as hazardous waste and disposed of appropriately at a hazardous waste landfill either onsite to be built or offsite, somebody would have had to do something, correct, with those wastes?
MS. TOWNSEND: Objection to form.
THE WITNESS: Yes. Yes.
BY MR. MEHTA:
Q. And are you saying that they would cost two million dollars to deal with that waste if it were classified as a hazardous waste?
A. I'm just saying that was the estimate in the documents I reviewed. I have not gone and done an evaluation of that specifically other than the costs that are being incurred now for those very same things looking back retrospectively -- taking those costs now and looking at what they would have cost back then using the time value of money.
Q. Nobody is treating coal ash CCRs as hazardous waste today, are they?

A. I didn't say the CCRs. I'm talking about the low volume waste. I'm talking about putting hydrochloric acid from cleaning metals -- cleaning part of the facility into these basins, would that have been less than a pH of two and need to be treated instead of just sending it straight to the basins. Which storm water is picking up contamination from the coal piles should have been just placed into the basin or should it -- could it have been diverted somewhere else for settling and treatment and then disposed.
Q. So you mentioned storm water. They would have had to -- back in 2004 at Dan River in order to convert from wet ash handling to dry ash handling, they would have had to do something with their storm water, correct?
A. Correct.
Q. And what would that have cost?
A. I don't know what the characteristics of storm water are. There's many facilities they don't have to treat storm water at all. It might have cost nothing other than the permitting cost.
Q. Do you know what it would cost?
A. No. I have said that. I don't know specifically at that time what it would have cost. The issue is if there was groundwater contamination. And so if you're saying -- I can put as much as I want in these

ponds because it might cost more but I don't really care about the groundwater, even if it's causing more ground water is what the analysis was if you only consider cost in that evaluation. You're not considering the impact to the environment. You're only -- and specifically groundwater, you're only saying what would have cost at that time.
Q. Well, I'm not actually saying anything. You are.
A. Right. Well, I'm just saying --
Q. I'm asking you questions.
A. -- there's an analysis beyond just the cost that has to be done.
Q. I understand. But are you saying the cost is immaterial to the analysis?
MS. TOWNSEND: Objection to the form.
THE WITNESS: No, I'm not saying that at all. It's a factor, but there are other factors as well that had to be considered.
BY MR. MEHTA:
Q. So you have to do a written assessment?
A. You have to do some kind of evaluation as to, again, if we're causing groundwater contamination we're going to just keep doing the same old thing, we're not going to change our processes, that's not dealing with the

102

issue. That's just pushing it down the road to some other time. So did they pull some of these out. Did they stop sending ash to the basins. They could have done groundwater remediation. If they said well, the only thing that we ca do is continue to send this material to ponds, they could have done groundwater remediation of some sort to control the plants. But there was nothing done with regard to addressing these issues. In fact more waste streams were placed into these ponds, like FGD scrubber waste water which clearly, in my opinion, shows contamination and it occurred because of that, even after they knew about groundwater contamination.
Q. That's from the scrubbers?
A. Yes. You can see a direct correlation at some of these facilities where the addition of these FGD waste waters lead to increased concentrations in groundwater very quickly after that occurred.
Q. So, Mr. Hart, you mentioned also that -- well, I think we were on the topic of if you converted from wet handling -- and, again, we're talking about a section in your report in which you indicate that DEC had knowledge as of early 2000s about something, and that you thought that certainly as to the Dan River plant since they had 10 years worth of monitoring something should have been done at that plant. Are we set? Level set again?

103

A. Yes, with regard to the groundwater contamination issue, yes.
Q. And that one thing that could be done is convert from wet ash handling to dry ash handling of coal ash?
A. Yes. Correct.
Q. Whether or not the pond itself was closed at the time, right?
A. Yes.
Q. So what would you have to do to the plant at Dan River in order to convert to a dry ash handling system versus sluicing the bottom ash from the boiler to the pond?
MS. TOWNSEND: Objection to form.
THE WITNESS: Are you talking about fly ash or bottom ash?
MR. MEHTA: Bottom ash.
THE WITNESS: I mean, I don't know specifically. I have read some of the technologies that are available. Basically it requires pulling out this ash and storing it in silos. But I don't know specifically. But I have looked at some of the --
BY MR. MEHTA:
Q. On a plant-specific basis, just use Dan River as an example, is there anything that would have had to

104

have been done at the Dan River plant in order to accommodate dry ash handling in 2004?
MS. TOWNSEND: Objection.
THE WITNESS: I'm not sure I understand your question.
BY MR. MEHTA:
Q. Well, let me try it this way. As I understand it, you may understand it better than me, wet sluicing, essentially the process is coal is stuck in a boiler, it's burned, residue drops to the bottom of the boiler, water sluices that residue to the ash pond. In very simplified terms, is that the process as you understand it?
A. Yes, in simplified terms, yes, I would say that's correct.
Q. So if you're not sluicing that ash to the ash pond, how do you get it out of the boiler?
MS. TOWNSEND: Objection.
THE WITNESS: You have got to have a way to drop it down or out away from the bottom of the boiler and into a conveyor system that takes it into silos or something like that?
BY MR. MEHTA:
Q. And what would that cost?
A. I mean, in what time frame are you talking about?

105

Q. I think you were saying as of 2004 at the Dan River plant they should have done something. One of the things you mentioned was conversion to a dry ash handling system.
A. Yes.
Q. Okay.
A. Are you talking about fly ash or bottom ash or both.
Q. Well, both. But we were specifically talking right then about bottom ash.
A. Well, I only know from the documentation in DEC's material that they felt those costs, depending on the plant, different, somewhere around 11 million to 35 million to convert to dry ash handling.
Q. And you don't know anything specific with respect to the Dan River plant, where it falls within that 11 to 35 million, do you?
A. I think they had estimates at each facility that were based upon a similar system that had been installed -- and I don't know where it was. Marshall maybe, I think.
Q. That was for fly ash, was it not?
A. I mean, they say dry ash conversion handling. So I don't know if it was fly ash or bottom ash or both. It's not clear from their documents what they're talking

about.
Q. Would it make a difference as to whether it's fly ash or bottom ash or both?
A. Yes.
Q. Okay. And if the Marshall conversion was fly ash, is there any estimate for the conversion to dry ash handling of bottom ash that you know of?
A. Just saying what's in the document is conversion to dry -- I mean conversion to dry ash handling. Doesn't specify if it's fly ash or bottom ash -- was in the 11 to 35 million dollar range. And I don't know if they increased it -- they took the Marshall number and increased it for bottom ash handling. I don't know.
Q. Whether they did or not is not reflected in the document that you're referring to, correct?
MS. TOWNSEND: Objection.
THE WITNESS: It just says here's the cost to convert to dry ash handling, estimated cost to convert to dry ash handling at these facilities.
BY MR. MEHTA:
Q. And the document that you're referring to is the 2003 10-year plan, correct?
MS. TOWNSEND: Objection.
THE WITNESS: I believe so, yes.
BY MR. MEHTA:

Q. Do you know how big the boilers are at any of the Duke plants, Duke Energy Carolinas plants? How tall?
A. How tall they are? Not specifically, no.
Q. Do you know if the bottom of the boilers is at grade?
A. I don't know specifically.
VIDEOGRAPHER: Counsel, you have about five minutes until I need to go off.
BY MR. MEHTA:
Q. When you gave that estimate of the 11 to 35 million to convert to dry ash handling, you do not know whether that estimate is fly ash alone or fly ash plus bottom ash, correct?
MS. TOWNSEND: Objection. Asked and answered.
THE WITNESS: That's correct.
MR. MEHTA: We're good to go off.
VIDEOGRAPHER: We're off the record at 12:30 p.m.
- - -
(Lunch break.)
- - -
VIDEOGRAPHER: We're back on the record at 1:06 p.m.
BY MR. MEHTA:

Q. Good afternoon, Mr. Hart.
A. Good afternoon.
Q. I think when we broke for lunch we had been speaking about essentially dry ash -- conversion of the Dan River plant specifically to dry ash handling --
A. Correct.
Q. -- in the 2004 time frame, is that right?
A. Yes, I believe that's correct.
Q. And you indicated, I think, that it would have been appropriate by that time with respect to the Dan River plant because of the groundwater monitoring data that was available with respect to the Dan River plant that something should have been done with respect to the ponds and the groundwater contamination that was evident from the ponds. Did I capture more or less what we were talking about before lunch?
MS. TOWNSEND: Object to form.
THE WITNESS: Yes, I think that captures it, yes.
BY MR. MEHTA:
Q. And you had a number of potentials of something to be done that we also discussed, correct?
A. Correct.
Q. You have examined groundwater issues and groundwater contamination issues at each one of Duke

Energy Carolinas coal-fired plants, correct?
A. Yes, I have.
Q. And they are -- the data and conclusions that you draw from the data are set forth in your testimony, correct?
A. Yes.
Q. And when I say testimony, I mean the written prefiled testimony that's Exhibit-1 to this deposition.
A. Yes. I understand.
Q. So as to the Allen plant, at what point in time should the discussion that we had with respect to Dan River have taken place for Allen?
A. They started groundwater monitoring there in 2004. I mean, I would say within, you know, several years from that initial groundwater monitoring.
Q. Does several years mean three or four?
A. Well, I think, you know, two years -- I think you could say one year worth of groundwater data is probably enough. But certainly, you know, two years is not unreasonable to evaluate concentrations, what's going on, maybe install some additional wells, find out what contamination is present, is it increasing, is it decreasing, is it -- what are the primary contaminants of concern. You know, I wouldn't go one monitoring event and say, you know, we should do something extraordinary. But

110

I think after several years of data I think it's reasonable that you have knowledge about the condition of the groundwater and that its impact is not going down in concentration and that, you know, there's an issue here that needs to be dealt with.
Q. So 2006, in that range, is what you're talking about in terms of considering options to alleviate the problem?
A. Correct. Yes.
Q. And are the options to alleviate the problem the same options as were present at Dan River in our discussion this morning?
A. Yes, I would say in general, yes. And they had already converted to -- I believe at Allen they had already converted to dry fly ash handling back in '84, I believe. So that -- you know, that wouldn't -- that had already been completed so --
Q. But not bottom ash handling?
A. But not bottom ash handling, correct.
Q. So the options would be close the basin, one option, correct?
A. That is an option, yes.
Q. Another option would be retrofit the basin to put a liner in it, correct?
A. Correct.

111

Q. Another one would be remove the ash more frequently and put it somewhere else, correct?
A. Correct.
Q. Reduce water flow to the basins, the active basins, correct?
A. Right, that is an option. Yes.
Q. And convert to dry ash handling even if you don't do anything to the basins, correct, for bottom ash?
A. Correct. Yes.
Q. And with respect to --
A. I mean, there's some others. You can do groundwater remediation.
Q. Understood. I'm focusing on the ash handling system.
A. Okay. Okay.
Q. And the -- how to deal with your ash if you're not going to deal with it the way you have been dealing with it. Understood?
A. I understand, yes.
Q. And you, again, have no basis for making a cost estimate for any one of those various options that we ran through as you sit here today?
MS. TOWNSEND: Objection.
THE WITNESS: Not in the 2006 time frame, no. There are some I said in 2003. There's some in the 2008

112

10-year CCR report as well that go over some of these -- some of the costs for some of those items. Not -- probably not liner retrofit.
BY MR. MEHTA:
Q. What is your understanding of the purpose of these 10-year plans?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I think part was an economic analysis certainly. How much ash -- you know, what's it going to cost to deal with the ash, but also how much can we sell, you know, to outside parties, how much are we going to generate. How much life is left in the pond. But certainly there were other things like conversion to dry ash handling, cost for that. Cost for closure were included in -- so I think it's kind of projecting into the future. I don't know what the future means. It could be in some cases a year from now or it could be 10 years from now, kind of what the cost might be to operate the basins. Close them out, that kind of thing.
BY MR. MEHTA:
Q. I mean, there's a whole series of them and each one is a 10-year projection, correct?
A. Correct. Yes.
Q. I mean, apart from whatever is said in the

113

10-year plan itself, do you have any understanding of the purpose of the 10-year plan?
A. Not other than what's in the document itself, no.
Q. I guess what I mean by that is you have not reached out to somebody at Duke Energy Carolinas to say what's the purpose of this plan?
A. No, I have not reached out to anybody at Duke Energy Carolinas, no.
Q. Did you ask the attorneys for the Attorney General to try and determine through data requests the purposes of these plants?
A. Not specifically, no.
MS. TOWNSEND: Objection.
THE WITNESS: I felt like they were fairly self-explanatory as to what the purpose was. I think it says in there what the purpose was and it goes -- they're detailed documents. Quite a bit of information in them.
BY MR. MEHTA:
Q. And, again, with respect to Allen, just like Dan River, you do not have an understanding of what plant modifications would have to be made, if any, at the Allen plant in order to accommodate dry versus wet ash handling, do you?
MS. TOWNSEND: Objection. Asked and

answered.

THE WITNESS: I mean, I know that some modification would have to be performed in order for that process to take place. But I don't know specifically what would have to be done.

BY MR. MEHTA:

Q. How did the fact that plant modifications would have to be performed factor into your analysis of the cost as to whether it's higher or lower if the work were done then versus now?

MS. TOWNSEND: Objection as to form.

THE WITNESS: I'm not sure I understand your question.

BY MR. MEHTA:

Q. Well, as I understand one of your sort of general conclusions is it would cost more today and it would have cost less if you had done the work at some point in the past, right?

A. Right. Yes. That's correct.

Q. How, if at all, did you factor into the equation of whether it would cost more or less, the cost of plant modifications which would have to be performed in order to effect a conversion from wet to dry ash handling?

MS. TOWNSEND: Objection as to form.

THE WITNESS: Well, I mean, to the extent

they're being conducted now, which they have to be for certain facilities, or have been, then those would be costs discounted whatever the costs are now. That's how I valuated it. I'm not sure those costs are in what I evaluated, the actual cost. I think most are ash retirement. I think what I'm -- used mine is mostly for coal ash basin remediation costs and groundwater monitoring and not the -- like a capital expenditure, I believe.

BY MR. MEHTA:

Q. Well, but if you were going to convert to a dry ash handling system from a wet ash handling system at Allen in 2006, you would necessarily have a capital expenditure, would you not?

MS. TOWNSEND: Object as to form.

THE WITNESS: Yes. Some facilities they never converted. They just retired the facilities and they never converted but --

BY MR. MEHTA:

Q. Allen is still operating today?

A. Right. So at Allen they had converted, I think, in 2018. You can certainly take those costs and say okay, what would have been those costs in 2006.

Q. But you didn't do that?

A. No.

Q. So in order to figure out whether at the Allen plant the cost to do the work in 2006 versus the cost to do the work in 2018 was more or less, you would have to take into account the capital expenditures that are required in order to convert from wet to dry ash handling, would you not?

MS. TOWNSEND: Objection as to form.

THE WITNESS: Yes. Those costs, of course, would be more than what I estimate because that would be an additional cost. So mine is almost like a low-end estimate. Potentially we could add those if I had those numbers and we could add those to the number that I came up with.

BY MR. MEHTA:

Q. Well, in order to figure out whether you ought to convert from dry to wet ash handling, wouldn't you want to know the relative cost of the capital expenditure required to do that and the costs associated with the groundwater issue that you're dealing with?

MS. TOWNSEND: Objection as to form.

THE WITNESS: That's an analysis you would have to look at is what are those costs -- how am I going to deal with this environmental contamination issue that I have got. Am I going to ignore it, am I going to address it somehow, through other means. I mean, it's all

factored in at the time. That's why I'm not saying you necessarily had to convert to dry ash handling, but something should have been done with regard to the groundwater contamination that was evident by 2006 at that facility and nothing was done. They didn't put more monitor wells in to determine the extent, they didn't -- you know, it came around to DEQ saying hey, you have got these issues, we need to find out what's going on with the groundwater at these plants.

BY MR. MEHTA:

Q. I'm sorry, they went to DEQ?

A. No, DEQ went to DEC and said we have been getting all this data, we have concerns about this data in 2009, and we need to find out where these wells are, you know, what the concentrations are, what your background levels are. All those things that should have been evaluated starting in when they first started collecting groundwater data.

Q. In your evaluation of this groundwater issue, was there any information that DEQ sought from Duke Energy Carolinas that was not provided to DEQ?

MS. TOWNSEND: Objection.

THE WITNESS: I wasn't looking at that specifically, so I don't recall anything. But I wasn't looking at that issue.

Deposition of Steven C. Hart

BY MR. MEHTA:
Q. Do you have any reason to believe that DEQ was not provided with whatever information it sought?
A. Well, for example, in the 2009 letter, the initial one says please provide us with the data -- a summary of the data that you have been collecting, where the locations are in relation to background or compliance boundary, those kind of things, and then tell us if you have exceedances how you're going to address those within the corrective action provisions of 2L.0106. That was not provided in their response, the specific corrective action provision.
Q. But the underlying data either was provided or had been provided to the DEQ, is that right?
A. The data was provided.
MS. TOWNSEND: Objection.
THE WITNESS: But there was no indication of how they planned to address the corrective action provisions of the 2L regulations, which is what was requested by DEQ.
BY MR. MEHTA:
Q. What was DEQ's response to that?
MS. TOWNSEND: Objection.
THE WITNESS: Their response was we need to put in more wells to -- at the compliance boundary because

that's the way we determine if you have a standard violation.
BY MR. MEHTA:
Q. And were the wells put in?
A. Yes.
Q. And did the wells generate monitoring data that was provided to DEQ?
A. Yes. Again, but there was never a this is what we're doing to address the corrective action provisions until after CAMA.
Q. So, Mr. Hart, I think we could walk through each one of the plants and I could ask you the same questions relating to when should the company have done something and what should the company have done, we can actually go through that at least with respect to when. But if I'm understanding your testimony correctly, the what should it have done is not really going to change plant by plant by plant, correct?
A. Well, yeah, it could depend on if they had implemented -- I think the primary thing would have been implementation of dry ash handling. If that had already been implemented, obviously you wouldn't need to implement it again. But not all facilities had converted to dry ash handling. So that would be the only kind of difference. I'm sorry, dry fly ash handling.

Q. Was there any facility that had converted to dry bottom ash handling?
A. Well, I think, you know, the documentation is somewhat conflicting on this.
Q. To your knowledge, do you know whether any facility had -- any Duke Energy Carolinas facility had converted to dry ash -- dry bottom ash handling?
A. My understanding from reading the documents is there was -- and I can't remember which facility -- they had converted to dry bottom ash but still had the ability to sluice bottom ash.
Q. And you don't know which facility that was?
A. I can look.
(Pause.)
MS. TOWNSEND: Expedite this by giving him a page number if you want me to. That's your call.
MR. MEHTA: Go right ahead.
MS. TOWNSEND: Page 81.
THE WITNESS: I thought it was in there. That was a correction I made earlier. And like I said, there was some -- there are conflicting information in the reports, so I can't remember -- and I don't think I included it in here about whether certain facilities -- a certain facility had converted to dry bottom handling but still had the ability to sluice bottom ash, which I think

they continued to do largely because they didn't want to -- probably -- I won't say -- because of the Bevill amendment issues.
BY MR. MEHTA:
Q. But you don't know why they continued to do whatever they continued to do?
A. I don't. There was some discussion about how they needed to be able to in certain circumstances wet sluice during startup and shutdown, but I wasn't really sure about that.
Q. Okay. So if there is a facility that did have the capability of doing dry bottom ash handling, obviously the option of converting to dry bottom ash handling would not be one of the options to be considered, right, because they had already done that?
A. Correct. Right. Or I think in the case of what I'm recalling is that they still had that ability. Even though they had converted they were still sluicing some bottom ash over. So they should stop doing that.
Q. But they would not have to build and expend the capital investment to build whatever was necessary in order to make that conversion for that particular plant?
A. Correct. Yes.
Q. So with that exception, if we went plant by plant by plant, are there any that come to mind in which

122

some option other than deal with the groundwater, I understand that, but I'm talking about option with respect to the coal ash handling, some option other than close the basin, retrofit the basin with a liner, remove ash more frequently, remove additional water flows and dry ash handling with respect to any plant?
A. I mean -- the other thing that I think is potentially lowering the water level. So having less hydraulic head. And I think I mentioned that before. I don't recall.
Q. Yeah. I guess I was lumping that into remove additional water flows but you're right. It's a little different.
A. Yeah. Okay. It's a little different. Correct. Yes, I think those were generally the options.
Q. Okay.
A. It could have been tried. Now, you know, it's possible that just removing the wastewater streams wouldn't solve the problem but it would be at least a step in the right direction as to well, we found out this didn't impact the groundwater greatly so we need to, you know, continue down the path of closure or whatever other alternatives might be available.
Q. And you have not, with respect to any of those options at any of the plants, done an evaluation of what

123

it would have cost to do those options in the time frame in which you say they should have been done?
A. I haven't done an independent evaluation. There are costs like I mentioned in some of the DEC documents about what some of those costs would be.
Q. Okay. And those are estimates based on whatever they went into the estimation process, correct?
A. Yes.
MS. TOWNSEND: Objection.
BY MR. MEHTA:
Q. Let me then do go plant by plant so that I can understand when as to each plant these other options should have been implemented. So we talked about --
A. Okay.
Q. -- Allen and you indicated probably around 2006 after you had two year's worth of groundwater monitoring data, correct?
A. Yes.
Q. And Belews?
A. Well, yes, other than the 1989 monitoring they were doing around the landfill, which was partly within the basin or near the basin, the ash basin, you know, they started doing this voluntarily groundwater monitoring there in 2007. So I would say -- which is a little late, I think, because of -- you know, at least they had told

124

DEQ that they were going to do this monitoring by 2004 -- by 2006. And so, you know, for whatever reason some of this monitoring didn't get done until much later than that. So, you know, I would say if they had kept to their, you know, schedule that they had told DEQ of doing groundwater monitoring by, you know, at least 2006 then you might say 2008. You know, I know they can't do groundwater monitoring at exactly the same time or put the wells in so there might be some staggering. But I would say certainly by 2008 to 2009 at the Belews Creek.
Q. So by 2008, 2009 in that general time frame, Duke Energy Carolinas should have been working to implement one of these alternative plans at Belews Creek?
A. Yes. Evaluating and, you know, looking at how are we going to address this groundwater contamination issue, specifically the source of the groundwater contamination which is the coal ash basin.
Q. I think the next one, at least alphabetically, is Buck steam station. When should this have occurred at the Buck steam station?
A. So they started at Buck in 2006. So I would say similar, you know, within a couple years by 2008.
Q. So similar time frame to Belews Creek?
A. Yes.
Q. And Cliffside?

125

A. At I mentioned similar to Belews Creek, I think they should have started sooner on the groundwater monitoring than 2008 because of what they had told DEQ and the knowledge about -- I think -- should have been installing wells or sampling by 2006. So I think by 2008, you know, they would have known they had issues at Buck.
Q. Dan River we've already talked about. I'm sorry, I cut you off.
A. No, it's fine. Yes. I was just saying at Buck.
Q. So your testimony is again in that similar to Belews Creek time frame, Duke Energy Carolinas should have been implementing some -- one of these options that were available in order to address groundwater issues?
A. Yes.
Q. Dan River we have already talked about, correct?
A. Yes.
Q. So the next one, I think alphabetically, is Marshall.
A. Yes.
Q. And so when should the company have been implementing a solution?
A. By, I think, the 2007 time frame is when they first started doing groundwater monitoring for the USWAG.

126

So by 2008, 2009 time frame.
Q. And I think the last one is -- oh, no. River Bend.
A. Yes. I would say 2008, 2008, 2009, same. They did start monitoring in 2008, but I think they should have started monitoring sooner based on information I have from other facilities as well as what they had told DEQ.
Q. So this one also is like Belews Creek?
A. Yes. Yes.
Q. I think the last one is W.S. Lee?
A. W.S. Lee. This one is similar to Dan River. So I would say around -- you know, they started monitoring in 1993. I would say by 2003 they certainly knew they had fairly high concentrations in groundwater. You could make a case that maybe it should have been sooner because there's no compliance boundary issue here. But I think, you know, just looking at other documents and the regulatory determination in 2000, I think the early 2000s would have been a reasonable time frame, 2003.
Q. So essentially similar to Dan River in that respect as well?
A. Yes. Yes.
Q. We have covered all the plants now, haven't we? I haven't missed one?
A. Yes, I believe so.

127

Q. Have you ever been in a utility rate proceeding?
A. No.
Q. Do you have any understanding as to how utility rates are set?
A. I have a general understanding, I don't know that -- certainly the specifics and -- of all the intricacies of that information.
Q. What is your general understanding?
A. Well, you're talking about regulated utilities or nonregulated utilities? I guess it would be regulated.
Q. A regulated utility. I don't think a nonregulated utility would be in a proceeding.
A. Right. Exactly. Well, I think generally if the utility company is asking for a rate increase, they need to supply information about why they feel that a rate increase is necessary to address their costs, their past costs. What those costs were and try to recover those potentially through the rate increase through the customers.
Q. And in order to justify what the costs were, what does the utility have to do?
A. I mean, I think they have to give an accounting of the costs that they have spent that they are trying to recover.

128

Q. And what are the factors that go into that accounting as they try to justify the costs they're trying to recover?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, I mean, certainly the actual cost of what was spent.
BY MR. MEHTA:
Q. Anything else?
A. Well, I'm sure there are other items, but I don't know specifically.
Q. Is the prudency of the expenditure one of the things that the utility would have to justify in order to recover its costs?
MS. TOWNSEND: Objection.
THE WITNESS: I believe that is the case, yes.
BY MR. MEHTA:
Q. Have you ever been through a prudence review with respect to a utility seeking to justify its costs other than this case, assuming you're in it for that purpose, which I don't know that you are?
A. No, I have not.
Q. Is the reasonableness of the costs a factor that a utility would have to justify in order to achieve recovery of the costs?

129

A. Yes, I think that's -- the costs have to be reasonable. That's my understanding.
Q. Mr. Hart, on page nine of your testimony right at the top lines, one to two. You indicate that despite the internal knowledge -- and the internal knowledge is what we have been talking about, the 10-year plans and things of that nature. I think that's what we've been talking about, correct?
A. Yes. Yes. Correct. The 10-year plans, the presentations that were made, those kind of things.
Q. You say DEC continued to sluice coal ash to some basins until 2018, correct?
A. Correct.
Q. I mean, in fact with respect to some basins they're still sluicing because those basins have not been closed, correct?
A. Well, I mean, if you read the information, the spreadsheets the DEC is giving they're saying they're not anymore. Although testimony says there was at least one facility that they still did until 2019, which seems to be in conflict to what DEC provided in a response. My understanding is they are not doing it anymore as of 2018.
Q. At every plant?
A. That's my understanding, yes.
Q. Regardless, I mean, we can figure that out.

It's a matter of record. It was legal for Duke Energy Carolinas to continue to sluice coal ash to some basins 2018, wasn't it?
MS. TOWNSEND: Object.
THE WITNESS: Well, I'm not a lawyer so I don't know about the legal conclusion of that practice or making that conclusion.
BY MR. MEHTA:
Q. What was the rest of the utility industry doing with respect to continuing to sluice coal ash to basins until 2018?
MS. TOWNSEND: Object.
THE WITNESS: I mean, every utility was different. Some of them -- well, I don't know. Some of them almost certainly were, some of them had stopped, some of them --
BY MR. MEHTA:
Q. Let me narrow the focus just to basically the southeast, so Virginia, North Carolina, South Carolina, Georgia. Utilities operating in those states were also continuing to sluice coal ash to basins until at least 2018, correct?
MS. TOWNSEND: Objection.
THE WITNESS: Yes, as far as I know. Yes. Yes.

BY MR. MEHTA:
Q. Did anybody, for example the DEQ or South Carolina DHEC, tell the company that it should not be sluicing coal ash to basins before 2018?
MS. TOWNSEND: Objection.
THE WITNESS: Yes, those are in the CCR rules and CAMA both have certain dates at which dry ash conversions needed to happen.
BY MR. MEHTA:
Q. And they happened, didn't they?
MS. TOWNSEND: Objection.
THE WITNESS: Yes, my understanding is -- at least the DEC facilities, my understanding is that they have or the plants shutdown.
BY MR. MEHTA:
Q. That is DEC is in compliance with the regulatory requirements of CAMA and the CCR rules as far as you know?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Well, I haven't done a whole evaluation about their compliance with the CCR rules or CAMA so I'm not sure. They weren't -- they're not in compliance with the ground monitoring rules, the 2L standards.
BY MR. MEHTA:

Q. 2L standards. But your statement is that it continued to sluice coal ash to some basins until 2018, and you indicated that under CAMA and the CCR rules there were some basins in which it could not do so in the 2014 to 2018 time frame I assume, since that's when those -- the earliest date would be the CAMA date was 2014.
MS. TOWNSEND: Objection.
MR. MEHTA: Or maybe I misunderstood what you said.
THE WITNESS: No. Yes, there was some requirements in CAMA and CCR rules to stop using these ponds, you know, if they didn't meet certain location restrictions or there was groundwater contamination, something like that.
BY MR. MEHTA:
Q. And whatever those restrictions were or directions were in either CAMA or the CCR rule with regard to stopping the usage of ponds, Duke Energy Carolinas complied as far as you know with those requirements, did it not?
MS. TOWNSEND: Objection.
THE WITNESS: As far as I know, yes. Specifically with regard to the CAMA and CCR rules and the ash basin.
BY MR. MEHTA:

Q. Well, prior to the passage of CAMA, did any agency of the State of North Carolina tell DEC that it should not sluice coal ash to its basins?
MS. TOWNSEND: Objection.
THE WITNESS: Well, certain facilities were retired by that time, you know, in the 2012 to 2013 time frame. So you couldn't take coal ash from another facility and bring it over there or something like that.
BY MR. MEHTA:
Q. Is there something that prevented you from doing that other than cost?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I don't -- I don't believe you can do that. Could be wrong. But I don't believe you could take -- the NPDES permits were specific to a facility and the process at that facility didn't say you can take sluiced water from Belews Creek and bring it to Marshall. Didn't say you could dispose of sluice coal ash from any facility that you want to into this basin and discharge it.
BY MR. MEHTA:
Q. Well, I mean -- so an academic question because it never happened anyway, did it? That is sluiced water from Belews Creek going to some other place other than the pond at Belews Creek?

A. Right. Correct.
Q. My earlier question to you, Mr. Hart, was until the passage of CAMA, did any agency of the State of North Carolina tell Duke Energy Carolinas that it should not continue to sluice coal ash to its basins?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Not that I'm aware of, no.
BY MR. MEHTA:
Q. Before the promulgation of the CCR rule, did South Carolina DHEC tell DEC not to sluice coal ash to the W.S. Lee basins?
MS. TOWNSEND: Objection. Same.
THE WITNESS: Well, again, some of these facilities retired before CAMA or CCR, the CCR rule. So I guess they didn't tell them that they couldn't but --
BY MR. MEHTA:
Q. But they were not retired at the direction of some state agency, were they?
A. No. No.
Q. So before the passage of the CCR rule and before the retirement of the W.S. Lee coal-fired plants, did South Carolina DHEC ever tell Duke Energy Carolinas not to sluice coal ash to the W.S. Lee basins?
MS. TOWNSEND: Objection as to the form.
THE WITNESS: Not that I'm aware of, no.

BY MR. MEHTA:
Q. Before promulgation of the CCR rule, did the United States Environmental Protection Agency ever tell Duke Energy Carolinas not to sluice coal ash to its coal ash ponds?
MS. TOWNSEND: Objection as to form.
THE WITNESS: Not that I'm aware of, no.
BY MR. MEHTA:
Q. Before the passage of CAMA, did the North Carolina legislature ever tell Duke Energy Carolinas not to sluice water to its coal ash ponds?
MS. TOWNSEND: Objection.
THE WITNESS: Not that I'm aware of. Not through -- you're talking about through specific past rule making or...
BY MR. MEHTA:
Q. Well, in the legislature I would say a law.
A. Okay. No, not that I'm aware. There were certainly draft regulations that discussed ash basin closure -- draft regulations that were considered before CAMA that would have potentially required closure of the ash basins and -- which would have obviously entailed stopping sluicing of coal ash.
Q. I think you referenced the draft. Was it regulation or legislation?

MS. TOWNSEND: Objection.
THE WITNESS: I guess probably statute.
BY MR. MEHTA:
Q. Statute?
A. Yeah.
Q. Okay. I think you reference a draft of statute or a proposed statute. What happened to that statute?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I don't think it ever became law. It was kind of one of the precursors, I guess, to CAMA.
BY MR. MEHTA:
Q. What conclusions do you draw from the fact that the legislature discussed something and decided not to do it?
MS. TOWNSEND: Objection.
THE WITNESS: I don't draw any conclusions from that.
BY MR. MEHTA:
Q. Why do you reference it in your report?
A. Well, because it was an indication that this was coming, that these addressing groundwater contamination at coal ash plants and closing ponds was coming. It was --
Q. Was it inevitable?

A. I feel so, yes.
Q. Based on what?
A. Based upon the increased scrutiny that these ponds were incurring, the groundwater -- you know, fairly significant groundwater contamination that was a result of these ponds, that something was going to be required to address these ponds as sources of groundwater contamination.
Q. And when you say that it was inevitable but also say that the legislature considered something and didn't do it, doesn't that impact your ability to say that something was going to be inevitable?
MS. TOWNSEND: Objection.
THE WITNESS: No. Because they eventually did it in response to the Dan River spill.
BY MR. MEHTA:
Q. How do you know it was in response to the Dan River spill?
A. Basically that's what -- I mean, I was here during that time frame.
Q. Do you know the mind of the legislature?
A. Well, that's my understanding of it, yes.
Q. What's your understanding based on?
A. Just my being a citizen of the State of North Carolina.

Q. So every citizen of the State of North Carolina was of the same mind as to why the General Assembly passed count?

MS. TOWNSEND: Objection.

THE WITNESS: I don't think I said that. What I said was, I as someone who's interested in these kind of things, in environmental contamination, environmental issues, was certainly aware as a citizen of North Carolina that there were going to be repercussions from this spill at Dan River and that included, you know, even before CAMA, a request to excavate the ponds at Dan River and to move the ash away from the river at Riverbend even before CAMA.

BY MR. MEHTA:

Q. When the legislature passes a law, does it tell you why it's passing a law?

MS. TOWNSEND: Objection.

THE WITNESS: In some cases it may.

BY MR. MEHTA:

Q. In CAMA did the legislature tell us why it was passing the law?

MS. TOWNSEND: Objection.

THE WITNESS: I don't recall. I don't know if it's specifically in the preamble to the rule or something like that. I don't know. Certainly in EPA

documents a lot of times they do, they give you a long preamble to this is why we're doing this. But I don't know specifically about CAMA. I do know that, you know, the Dan River spill was a significant event in the history of coal ash pond and CCR management. The other being the 2009 TVA release. Kind of bell weather events that occurred that lead to legislature to deal with these ponds.

BY MR. MEHTA:

Q. Do you know what was in the mind of the legislature when it passed amendments to CAMA that went into effect in 2016?

MS. TOWNSEND: Objection.

THE WITNESS: Not specifically, no.

BY MR. MEHTA:

Q. Should DEQ have told Duke Energy Carolinas at some point prior to the passage of CAMA that it should stop sluicing coal ash residue to the coal ash ponds?

MS. TOWNSEND: Objection.

THE WITNESS: In my opinion the clear evidence of groundwater contamination should have led to an evaluation of remedial options to address the groundwater contamination. The State doesn't usually tell you this is how you have to address this issue. They say this is the issue and you need to address it, typically.

Now, in the case of CAMA they actually laid out some -- this is what you have to do because of the inaction to that date with regard to these ponds.

BY MR. MEHTA:

Q. Well, should the DEQ have been more explicit about what it wanted the company to do prior to the passage of CAMA?

MS. TOWNSEND: Objection.

THE WITNESS: Well, it was explicit even before CAMA when DEQ said you need to close the basins at Dan River, excavate them and move the ash away from the river at Riverbend even before CAMA.

BY MR. MEHTA:

Q. That was after the Dan River spill?

A. Right.

Q. Okay. Let me amend the question.

A. But before CAMA was passed because of the seriousness of the issue --

Q. Let me amend the question.

A. Okay.

Q. Should the DEQ have told Duke Energy Carolinas to quit sluicing coal ash into coal ash pounds, basically quit wet handling of coal ash prior to the Dan River spill?

A. It's not something I think DEQ typically in my

experience directs people to do, unless, you know, in the case of CAMA they felt that it was necessary. So in my experience they say you have an issue and you need to deal with it, come up with a plan to deal with it. That wasn't happening, and then after CAMA -- I mean after the release of Dan River where there was significant release, then there was this we need to do something -- come up with specific rules on how to deal with this.

Q. In the course of your investigations into all of the documents that you looked at and the databases that you looked at, did you come across any guidance from the DEQ as to how one would close an ash basin if one were going to close an ash basin?

A. No. Again, that's usually up to the -- they might have some -- well, in some cases they have some guidance. I don't know specifically for coal ash basins, but that usually is up to the individual regulated company to say here's how we're going to address this issue, and then DEQ can either review and approve it or say this -- we reject that or we have some comments on it and this is how we think you should do it differently.

Q. What is your understanding of the interaction between Duke Energy Carolinas and DEQ with respect to how one would go about closing an ash basin if one wanted to close an ash basin prior to the Dan River spill?

142

MS. TOWNSEND: Objection.
THE WITNESS: I mean, the only thing I remember is that there are -- some indications in the reports, internal DEC reports, that DEQ didn't have any particular guidance for closing the coal ash basins. So it was up to the company, DEC, to come up with a plan to do that. I mean, they generally laid out several options, one was clean closure, full removal. Another was a hybrid plan where they would remove some of it to another location in the basin to consolidate those materials in clean close part but cap another area. And the other was in-place closure where they basically closed the pond in place. All of those were at that time, I think, viable options. Potentially. Depending on the specifics of the facility.
Q. And what would change depending on the specifics of a facility?
A. Well, depends on, you know, the sensitivity of the issue. If they have contaminated water supply wells nearby, they would say we need to clean close this. It could depend on how much land they had potentially to, you know, construct a landfill to clean out the material. I think those are, you know, some of the thought process -- they went to cost is certainly an issue, that that was under consideration. You know, just depends on the

143

facility and whether it was below the water table or not would be an important factor, whether there was ash below the water table. Whether it had been placed below the water table so it would continue to leach out or whether it was all above the water table and, therefore, once you de-water the basin it would be dry. Those are some of the factors that -- I'm sure there are many others.
Q. And is it your contention that no interaction between DEQ and DEC was taking place trying to figure out these various factors?
MS. TOWNSEND: Objection.
THE WITNESS: I never made that contention, no.
BY MR. MEHTA:
Q. Well, let's see. On page nine starting at line 19 of your testimony and then moving on to page ten through line four, you have a comment concerning the USWAG action plan. U-S-W-A-G.
A. Yes.
Q. And you indicate that DEC -- this is on top of page 10. You indicate that DEC just submitted the data to DEQ without evaluation or responsive action and implied that the data were consistent with background conditions. Do you see that?
A. Yes.

144

Q. Well, when the companies submitted the data that you're talking about, what did DEQ do with it?
MS. TOWNSEND: Objection.
THE WITNESS: DEQ, as far as I know, took it and placed it in their files until around 2009. They said hey, we can get all this data to you, we can't tell what it is. We don't know where -- we've got data and it shows 2L exceedances so we need more information.
BY MR. MEHTA:
Q. So from whenever the date was generated which would have been as early as 2006 --
A. 2004.
Q. 2004 to 2009, DEQ did nothing with the data, is that your testimony?
A. That's what it appears, yes.
Q. What should have been done with the data?
A. Well, it's not DEQ that should have done something. It's DEC that should have done something.
Q. Are you saying that DEQ didn't have to do anything with that data?
A. They could have, but I don't know that they had an obligation to. Especially considering the fact that they're typically understaffed and, you know, rely on the regulating community to report to them when they have issues and they said they were going to follow the USWAG

145

voluntary action plan. If we have a problem in groundwater, we're going to come to you and say here's what we found, we have got issues, and we're going to develop a corrective action plan to deal with it. That was the commitment that was made in that document between regulatory agencies and the utilities.
Q. Well, when DEQ examined the data and saw that there were exceedances of the 2L standards, should DEQ as early as 2004 have said we need a corrective action plan?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I think they -- they needed more information. Just submitting data doesn't tell me anything about where these wells are in relation to the facility, are they background, are they -- you know. I don't think -- DEQ certainly could have, as early as 2004, but I think the USWAG made it clear that DEC was supposed to do that and work with the regulatory agency and go to them and say we have found these issues and we need to deal with it and develop corrective action plans.
BY MR. MEHTA:
Q. Is it your testimony that DEC did not work with its regulator in order to evaluate whatever the data they were producing with respect to groundwater monitoring at these various plants?
A. Not until probably 2010 time frame, 2011, no.

Q. On page 10 looking at lines 11 to 13, you indicate that DEC chose to wait until regulatory agencies noted groundwater contamination concerns from the date of submittals. Do you see that?
A. Yes, I see that.
Q. So what did these agencies do after they noted that?
A. Well, required additional assessment to determine -- evaluate -- in the case of North Carolina facilities evaluate conditions at the compliance boundary.
Q. When you say the regulatory agencies, are we talking about the DEQ?
A. Well, and DHEC as well, D-H-E-C, South Carolina.
Q. Both of the environmental regulatory agencies, correct?
A. Right. Yeah, I think in the case of the W.S. Lee plant, they went to them and said we need a special order on consent to address the ash basins and the groundwater contamination.
Q. Which was entered and from which work was done, correct?
A. Several decades after they found contamination, yes.
Q. Well, it was entered and done when DHEC wanted

it entered and done, correct?
A. I don't know when DHEC wanted it done, but they gave them a special order consent 2015, I believe.
Q. Have you seen any evidence that there was a request for a special order of consent or on consent or anything else from DHEC with respect to the W.S. Lee plant before the special order on consent?
MS. TOWNSEND: Objection.
THE WITNESS: I don't recall seeing anything specifically. Again, the data we have for the W.S. Lee -- or the information we have for W.S. Lee is fairly sparse I would say, from the regulatory agency.
BY MR. MEHTA:
Q. So you have no reason to believe that whatever DHEC wanted with respect to the W.S. Lee plant was supplied by Duke Energy Carolinas whenever they asked for it?
A. I mean, they think they did supply it to them, you know, in accordance with their permit. The issue is should they have acted upon that data sooner instead of waiting for DHEC to come to them and say hey, we have a real problem here, we need to issue a special order by consent. There are other ways to address contamination without a special order by consent earlier.
Q. Let me try to rephrase my question. I wasn't

talking about the monitoring data. I was talking about enforcement -- some kind of enforcement action with respect to whatever their data was showing, was there any -- did you find any indication that DHEC was seeking some kind of enforcement action before the time frame of which a special order on consent was entered?
A. Not that I can recall, no.
Q. If you flip over to page 11, Mr. Hart.
A. Okay.
Q. Actually, I think we have more or less covered since we spent a good deal of time talking about each one of the individual plants your item number 10 --
A. Okay.
Q. -- that's on page 11 -- 10 and 11. I don't think we have to go through that at this point.
Skip over to page 12. When you reference at the top of the page lines one through three, the expedited response increased scrutiny and reduced confidence after Dan River -- after the Dan River release certainly lead to increased costs. Do you see that?
A. Yes.
Q. What specifically are the amounts of the increased costs?
A. I haven't done evaluation of that. It's just a statement that if you respond to something in an expedited

fashion, and as a result of increased scrutiny or reduced confidence, you know, there's almost certainly going to be increased cost because I'm doing something quicker is -- I can't think of a case where doing something quicker is not more cost effective, especially on a construction type project than doing it in a regular time frame.
Q. But you can't put a dollar figure on it?
A. No, I haven't done that estimate.
Q. And similarly with respect to lines four through, I guess it's seven or really 13, that last point, number fourteen of your testimony. You don't know specifically the amount of increased cost, do you?
A. Well, I did, you know, discuss that earlier. The increased cost based upon the time value of money associated with these closure of its coal ash basins depended on when, you know, that should have started.
Q. I guess to make a finer point on it, you have not done an evaluation of what should and could have been done at those earlier times, what that would have cost and compared it to the actual costs incurred today, is that correct?
A. Yes, that's correct. Because under this knowledge that costs today certainly are going to be higher than they are back then because they're using -- they're being required to address the coal ash basins and

probably the most expensive way, that is by full removal.
Q. And Duke Energy Carolinas was not in favor of full removal at all of these basins, was it?
A. That's my understanding.
Q. In fact, it litigated with the DEQ and its lawyers or the attorney general or lawyers from the Department of Justice for the better part of a year on that issue as to whether it was reasonable to require full removal, isn't that right?
MS. TOWNSEND: Objection.
THE WITNESS: That's my understanding, yes. And then they agreed to do that. DEC agreed to remove.
BY MR. MEHTA:
Q. And the Attorney General or the DEQ and various environmental interveners agreed to it too?
MS. TOWNSEND: Objection.
MR. MEHTA: Correct?
THE WITNESS: Yes, that's my understanding. Yes.
BY MR. MEHTA:
Q. And they also agreed that some portion of what DEQ originally wanted would not have to be done, correct?
A. I think that's correct, but I don't know the specifics of that.
Q. I mean, the parties reached a settlement

agreement in which they all compromised some of their original litigation positions, correct?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I know there's a settlement. I don't know if all parties compromised. I don't have that information to know which specific party was -- their concerns were.
BY MR. MEHTA:
Q. Skip over to page 22.
A. (Witness complies.)
Q. And you note at lines, looks like, six through 10 of the standards for chromium changed in 2010. Do you see that?
A. Yes.
Q. Is that the North Carolina standard?
A. Yes. I think it was January 1, 2010 they would go back and find the effective date.
Q. Do you know why the standard was changed?
A. Well, I think the EPA changed the drinking water standard to 10 before that and then it was based upon these, you know, updated toxicity studies. So they changed the maximum contaminant level for drinking water. EPA had done that in 2006 or eight, I can't remember.
Q. Why did the EPA do that?
MS. TOWNSEND: Objection.

THE WITNESS: Well, felt it was necessary to protect human health.
BY MR. MEHTA:
Q. Well, so I guess from 1979 until 2006 the standard -- well, actually in North Carolina I guess from 1979 when the 2L standards were first introduced until 2010, a span of 31 years, the standard was five times higher, correct?
A. Five times higher than what?
Q. Well, the standard was 50 micrograms per liter in 1979 and it stayed 50 micrograms per liter until 2010, correct?
A. Correct.
Q. And in 2010 it was changed to a fifth of that, 10 micrograms per liter, correct?
A. Correct.
Q. Was the DEQ unreasonable in not changing the chromium standard in that 31-year period?
A. I don't have any basis to make that determination. They have to go through formal rule makings. I think when the EPA changed their standard to something lower than the 2L standard then that started the process of lowering the standard -- the groundwater standard in North Carolina.
Q. And the EPA standard is a drinking water

standard, correct? Or have I got that wrong?
A. No, it's a drinking water standard.
Q. And the 2L standard is not a drinking water standard?
A. It's a groundwater standard. It can -- in part based upon consumption of groundwater.
Q. So was the public at risk for those 31 years that the DEQ had not changed the chromium standard between 1979 and 2010?
MS. TOWNSEND: Objection.
THE WITNESS: I don't know what you mean by risk. There's a risk for everything we do. Every time we -- there's always a risk. Is there an increased risk? Potentially. But I think it was based upon, you know, the data they had at the time. But they could have potentially been exposed to an increased risk during that time.
VIDEOGRAPHER: You have about five minutes before I need to go off.
MR. MEHTA: We can stop. This is a good spot.
VIDEOGRAPHER: We're off the record at 2:30 p.m.
- - -
(A break was taken.)

154

\- - -

VIDEOGRAPHER: We're back on the record at 2:38 p.m.

BY MR. MEHTA:

Q. Mr. Hart, if you would skip over to page 28 of your testimony.

A. Okay.

Q. We may have covered some of this, but let me just ask you if you know why DEQ did not require the company to take action until 2011?

A. I mean I don't know -- well, I don't know specifically.

Q. Is it your opinion, Mr. Hart, that DEQ has done an adequate job of fulfilling its responsibilities to the citizens of North Carolina with respect to Duke Energy Carolina's coal ash?

MS. TOWNSEND: Objection.

THE WITNESS: I haven't evaluated that, so I don't know. I haven't formed any conclusion or opinions about that.

BY MR. MEHTA:

Q. So you haven't evaluated it why?

A. Just not something I evaluated. I looked at DEC's actions as noted in my testimony, in the early part of my testimony. I don't think DEQ, by my experience,

155

acted differently than it typically does. They rely on the regulated community to identify issues and then -- you know, for them to address. You know, they're not -- if you just send in data like an NPDES permit and just send it in somebody may not look at it, but it's certainly appropriate to tell the DEQ that you're having an exceedance. And so that you need to address it.

Q. Is it your testimony that DEQ was not aware that there were exceedances?

MS. TOWNSEND: Objection.

THE WITNESS: It's not clear, but it doesn't appear that they really looked at the data until 2009. The DEQ didn't look.

BY MR. MEHTA:

Q. Is it your testimony that DEQ was not aware that there were exceedances from the groundwater monitoring data that had been submitted to DEQ since 2004 until 2009?

MS. TOWNSEND: Objection.

THE WITNESS: I don't know whether they were aware or not. From what I read it looks like they started doing evaluation of the data in 2009.

BY MR. MEHTA:

Q. That doesn't mean that they were not aware of it earlier than 2009, does it?

156

A. It does not. But they couldn't have done an evaluation of the data until they had the additional information they requested, like maps and which wells were background and that kind of thing.

Q. That data was supplied to them upon their request, was it not?

A. It was.

Q. Did the request come in in 2009?

A. Yes.

Q. Should the request have been made earlier than 2009?

MS. TOWNSEND: Objection.

THE WITNESS: No, I think DEC should have brought it to the attention of DEQ within -- you know, within a couple years of them having confirmed these groundwater contamination exceedances in accordance with the USWAG plan that said if we identify issues we're going to come to you and discuss this with you and come up with a corrective action plan to deal with the contamination issues. That was their commitment to the regulatory agencies.

BY MR. MEHTA:

Q. Skip over, if you would, to page 50.

A. Okay.

Q. You might have to actually start on page 49

157

because I think the sentence is a carryover sentence. And the sentence indicates that DEC was sluicing pyrites to the ash basins at the Allen facility, which appears to be in conflict with the advice given in the document that you're referring to, correct?

A. Yes.

Q. Was that action at Allen contrary to or in violation of any laws or regulations of State of North Carolina?

MS. TOWNSEND: Objection.

THE WITNESS: Not that I'm aware of. Sluicing pyrites?

MR. MEHTA: Correct.

THE WITNESS: No.

BY MR. MEHTA:

Q. Was it in contrary to or violation of any federal laws or regulations?

MS. TOWNSEND: Objection.

THE WITNESS: I don't believe so, no.

BY MR. MEHTA:

Q. Skip over to page 63.

A. (Witness complies.)

Q. And line -- actually I guess here at line 12 is where you talk about that prior North Carolina legislation, correct?

A. Correct.
Q. Proposed legislation that would require monitoring corrective action and phase out of ash basins that were constructed before January 1, 2010, correct?
A. Correct.
Q. Is that the legislation that you were -- what we were talking about earlier that was not adopted by the general assembly?
A. That's correct, yes.
Q. And you draw no conclusion from the fact that it was not adopted by the General Assembly?
MS. TOWNSEND: Objection. Asked and answered.
THE WITNESS: Well, I think there's various reasons why proposed legislation is adopted, but I don't know in this specific case what it is.
BY MR. MEHTA:
Q. And then you go on to say that the documents also indicate that closure of ash basins is likely to be in-place closure and capping, correct?
A. Yes.
Q. And today we know that in-place closure and capping is not acceptable to the DEQ, correct?
A. Well, my understanding is that at CAMA because Dan River and River Bend were high risk sites, those would

not have been considered for in-place closure. The others could have been but for the DEQ rejected the closure plans that Duke submitted for the North Carolina facilities.
Q. All of which said we should close in-place and cap?
MS. TOWNSEND: Objection.
MR. MEHTA: Correct.
THE WITNESS: I think -- yes, there was some component of in-place closure, yes.
BY MR. MEHTA:
Q. So in 2011 had the company closed all its basins and closed them by the cap-in-place method or the hybrid method, what would happen now in 2020 that the DEQ has said thou shall not do that?
MS. TOWNSEND: Objection.
THE WITNESS: I don't know that we can predict now what would happen. But usually if there has been -- and this happened with some of the other basins, they were closed in place. They didn't make them excavate out. Now, they may have addressed groundwater contamination, which they should have. It may have been a longer term source of groundwater contamination that would have had to be addressed. But in my experience, you know, with DEQ, once these are closed out then they usually don't make you dig them back up. But I can't say for

certain whether that would have occurred.
BY MR. MEHTA:
Q. The Dan River spill -- had the Dan River ash basin been closed and capped in place, the Dan River spill could have occurred anyway, couldn't it?
MS. TOWNSEND: Objection.
THE WITNESS: Well, hopefully in their evaluation of the closure options and the investigations they would have heeded the warnings of the engineers about how there's this line that has issues that needs to be dealt with. Now it's also dry, then very little would have leaked out potentially because it was dry, it wasn't wet. Basically because it was wet it drained out through the hole. But if it's dry it may have only had a very small volume. Likely would have had only had a small volume, much smaller volume if they didn't address the --
BY MR. MEHTA:
Q. I guess the premise of the question would be they didn't discover the pipe that was ultimately the problem for whatever reason?
A. Well, they knew it was there. It was discovered. They chose not to repair it.
Q. Well, I don't think anyone knew of the condition of the pipe when they chose not to repair it, did they, Mr. Hart?

A. I don't know specifically.
MS. TOWNSEND: Objection.
THE WITNESS: My understanding is they're aware of the pipe, certainly.
BY MR. MEHTA:
Q. They were aware that the pipe existed, correct?
A. Yes.
Q. And they were not aware, unless you tell me that you know something to the contrary, of the condition of the pipe, correct?
MS. TOWNSEND: Objection.
THE WITNESS: Right. I think that's right. People had recommended that they determine the condition of the pipe, but they had not done that. That's my understanding, you're correct.
BY MR. MEHTA:
Q. Let's see. I guess on page 67 and 68, you discuss a PowerPoint presentation dated November 13, 2013, right?
A. Yes. Well, I don't think it's a Power -- could be wrong, but I'm not sure this is a PowerPoint presentation. I could be wrong.
Q. Well --
A. I think it's summaries of each facility. I don't believe it's a PowerPoint of groundwater data.

162

Q. You're correct. The next one was a PowerPoint, January 13th.
A. Yes. Correct.
Q. And you, on page 68, lines 15, 16, you indicate that based on the level of exceedances it was and is a potential risk to human health and the environment, correct? That is what you state. Page 68.
A. Yes. Yes. I'm sorry. There at the bottom of the paragraph. Yes, that's what it says.
Q. So was DEQ aware, based on the level of these exceedances, that there was and is a potential risk to human health and the environment?
MS. TOWNSEND: Objection.
THE WITNESS: I'm sorry, you're asking was DEQ aware of this?
MR. MEHTA: Yes.
THE WITNESS: As far as I know, yes.
BY MR. MEHTA:
Q. Skip over to page 77. Actually, before we get there, I guess starting at page 73, running over to page 122 you have presented a series of plant-by-plant evaluations of groundwater monitoring data, correct?
A. Yes. Well, as well as information about the plants -- the coal ash basins themselves. Brief introduction. Introductory information.

163

Q. So basically a site-by-site description of the various results of the monitoring data, 2L results and also, you know, plant descriptions, ash basin descriptions for each plant and basin, right?
A. Yes. Focusing primarily on a time frame between the start of groundwater monitoring and before CAMA. I mean, we include data after certainly but it's really kind of what was the knowledge of the data in that time frame.
Q. Okay. And the knowledge of the data is known to Duke Energy Carolinas and also to its environmental regulator, DEQ, correct?
MS. TOWNSEND: Objection.
THE WITNESS: I mean, as far as I know, yes, they have submitted the data to DEQ.
BY MR. MEHTA:
Q. So, for example, on page 77, lines 10 to 12, you indicate something about exceedances of 2L standards of the compliance boundary in 2004, correct?
A. Correct.
Q. At the -- I guess this is the Allen plant, right?
A. Correct.
Q. So DEQ knew that too, right?
MS. TOWNSEND: Objection.

164

THE WITNESS: Well, I don't think they knew where some of these wells were until 2009 or '10 until they submitted the maps 2009.
BY MR. MEHTA:
Q. If they were interested they could have figured out where the wells were long before 2010, correct?
MS. TOWNSEND: Objection.
THE WITNESS: Yes. If they had -- they could have asked, yes.
BY MR. MEHTA:
Q. And on page 105 --
A. Okay.
Q. -- we are talking about the Dan River plant, correct?
A. Yes.
Q. And the Dan River plant was one of those in which groundwater monitoring was required as part of an NPDES permit re-issuance as early as 1993, correct?
A. Correct.
Q. And you indicate that 2L standard exceedances were detected at the site as early as 1993, correct?
A. Correct.
Q. Do you know why DEQ did not require the company to take any action until 2010?
MS. TOWNSEND: Objection.

165

THE WITNESS: I don't know why DEQ --
BY MR. MEHTA:
Q. Is DEQ wrong in not requiring some action before 2010?
MS. TOWNSEND: Objection.
THE WITNESS: I mean, certainly I think they should have, but I think DEC was wrong in not looking at this data and seeing obviously that there was some concerns associated with groundwater contamination from this basin. I mean, it's unmistakable that there's groundwater contamination issues at these basins.
BY MR. MEHTA:
Q. At the Dan River plant?
A. At every plant. And I don't know that the -- you know, that -- in my experience companies usually address their issues of groundwater contamination because they -- they need to. It's the right thing to do. They don't want it to get offsite. They want to address it with DEQ and it's not typically ignored. The longer it takes to address these, of course the further contamination can go, the concentrations can get higher. So the longer you wait, the cost will go up because the contamination is -- you can see it in some of these where contamination goes up significantly over time.
Q. But that depends on what you actually have to

166

do in order to remediate the contamination.
MS. TOWNSEND: Objection.
MR. MEHTA: Correct?
THE WITNESS: I would say no matter what the costs are going to go up over time just, if nothing else, from the time value of money. But if the contamination is further away, it's certainly going to potentially cost more and it's going to take longer to clean it up even if you don't do anything active than it would have been to address it earlier. Certainly the higher the concentration, it's going to take longer to clean up.
BY MR. MEHTA:
Q. And if the ultimate solution -- this is more or less hypothetical, not tying it to any particular plant or pond -- is to let nature take its course and that solution would have been the solution in 2010 and it's the solution in 2020. Is there a material difference of costs?
MS. TOWNSEND: Objection.
THE WITNESS: Certainly.
BY MR. MEHTA:
Q. In what way?
A. If you close the basin sooner then you would have removed the source.
Q. Let me clarify my question. I'm not talking about basin closure. I'm talking about groundwater

167

contamination. If the ultimate solution is to let nature take its course and let the groundwater clean itself and that solution would have been the solution in 2010 just as much as it is in 2020, is there a material difference in cost?
MS. TOWNSEND: Objection.
THE WITNESS: Sure. I mean, you got to get rid of the source first. You'll never clean up the groundwater if you don't get rid of the source. So, if you had just started groundwater monitoring and natural attenuation in 2010 but you didn't address the source and try to address the source by either these things we talked about, then the groundwater contamination is going to last that much longer until you remove the source. And then the concentrations may go up. So instead of 30 years monitoring, it might be 50 or a hundred years of monitoring.
BY MR. MEHTA:
Q. So it's the monitoring cost that would go up in that circumstance?
A. Well, the length of time that's monitored.
MS. TOWNSEND: Objection.
THE WITNESS: And then plus the increase in cost over time just from the time value of money. Inflation costs.

168

BY MR. MEHTA:
Q. When you say the increase in cost over time due to inflation, are you talking -- let me just make sure I understand what you're saying. Does that mean the costs of monitoring equipment rise over time and the costs of people to perform the monitoring rises over time? Is that what you're talking about?
MS. TOWNSEND: Objection.
THE WITNESS: Yes. Increased costs for people, healthcare, overhead for employees, analytical costs go up. All those kind of things that are, all things being equal, inflation driven.
BY MR. MEHTA:
Q. If you skip over to page 120. I think we're talking here about the W.S. Lee plant.
A. Yes.
Q. And, again, lines 19 and 20, you indicate concentrations and down gradient wells exceeded the MCLs. Is the MCL a drinking water standard?
A. Yes.
Q. So in South Carolina they don't have our equivalent of a 2L standard, or do they?
A. Well, they have groundwater standards, but they reference the drinking water MCL.
Q. So their groundwater standards effectively

169

equate to the groundwater standards?
A. Correct. Yes.
Q. So, anyway, you indicate that the concentration in the down gradient wells exceeded the standards, whatever they were. Is this a fact that South Carolina DHEC was aware of at the time?
A. I would assume so, but I don't have any documentation to that effect. Again, the information we have for W.S. Lee is somewhat limited, but I don't have any reason to believe that they didn't have the data.
Q. Mr. Hart, on page 122, very bottom starting at line 19 and then going on to page 123, line three.
A. Okay.
Q. You posed a question, since you told me that you did the Q and A, that says based on your analysis before the Dan River spill happened did DEC undertake reasonable and prudent actions.
A. Yes.
Q. Let me ask you this. Based on your analysis, before the Dan River spill, did DEQ undertake reasonable and prudent action of practices in a timely manner to respond to groundwater contamination at its ash basins and address closure at Duke Energy Carolinas' ash basins and address closure of those basins?
MS. TOWNSEND: Objection.

THE WITNESS: Well, again, like I said, I didn't evaluate that particularly with regard to what DEQ did.

BY MR. MEHTA:

Q. So you have no opinion?

A. Well, I think certainly they could have responded earlier to the identification of contamination. Again, I think as I mentioned before, certainly DEC had told DEQ that they would come to them if there were issues identified in the USWAG groundwater monitoring. That's what the action plan said. And they would then develop a corrective action plan to deal with the groundwater contamination. That didn't happen.

Q. How do you know it didn't happen?

A. There's no indication that it happened. It didn't happen until CAMA. 2009 they said we need some more information about this. DEQ did. And then they did some more assessment. But they didn't -- you know, there was no corrective action conducted until 2014. There wasn't even a receptor evaluations really conducted until 2014.

Q. When you say corrective action was not taken until CAMA and then you said 2009. So CAMA of course is 2014 --

A. I just meant DEQ looked at the data and had to

go to DEC and say this groundwater data could be a problem. We need some more information. The commitment that was made by the utility industry was that the utility industry, if they identify the problem, would go to the regulatory agency and say we have a problem and we want to work with you to come up with a corrective action to address the contamination.

Q. Did you, in the course of your investigation, undertake to figure out why if that communication was not made why it was not made?

MS. TOWNSEND: Objection.

THE WITNESS: I don't know. There was, I think, some belief that iron manganese and some of these other metals didn't matter. Like they're secondary MCLs. Well, there's no secondary MCLs in the groundwater standards for North Carolina. It doesn't matter. They still pose a risk.

BY MR. MEHTA:

Q. What risk do they pose?

A. Well, I mean, there's certainly indication -- I mean, anything in high enough concentration or exposure will pose some risk.

Q. What risk did iron and manganese in the groundwater at these sites at some level in exceedance of the 2L standards pose to anybody?

A. Oh, I think there's a direct contact concern potentially, there's a concern for the environment with regard to, you know, many of these were on the rivers. And so you can have effects from -- with regard to biological effects. Certainly there was some indication that there were water supply well effects, especially at the Allen plant. But the 2L standards don't say it has to pose a risk. It just says you've got to address it if you've got a problem. In some fashion you have to eliminate the source of the contamination and then you have to address the contamination and clean it up.

Q. Why is Piedmont soil red?

A. Primarily because of the iron oxides that are present.

Q. What is the chief law enforcement agency in the State of North Carolina?

MS. TOWNSEND: Objection.

THE WITNESS: I don't know. I guess the Department of Justice.

BY MR. MEHTA:

Q. You're right. So based on your analysis, Mr. Hart, before the Dan River spill happened, did the chief law enforcement agency of the State of North Carolina undertake reasonable and prudent actions and practices in a timely manner to respond to groundwater contamination at

the Duke Energy Carolina ash basins and address closure of Duke Energy Carolinas's coal ash basins?

MS. TOWNSEND: Objection.

THE WITNESS: I certainly haven't formulated an opinion on that. I don't really -- wouldn't even know how to start because I wasn't sure that DOJ was the chief law enforcement agent in the state.

BY MR. MEHTA:

Q. Well, to the extent that you indicate as you did that DEQ certainly could have taken action earlier than it did, the folks who would represent DEQ in connection with any kind of an enforcement proceeding also could have taken action earlier than they did, correct?

MS. TOWNSEND: Objection.

THE WITNESS: They could have. If you're -- I guess the underlying theory here is that you don't do anything unless you're forced to do it by some regulatory agency or through some specific -- you have to be threatened with enforcement before you do something that's the right thing to do or that's required by the rules. Generally I don't think people want to be enforced to do something. At least the clients that I work with try to avoid that.

BY MR. MEHTA:

Q. Based on your analysis, again, before the Dan

River spill happened, did the public staff of the North Carolina Utilities Commission undertake reasonable and prudent actions and practices in a timely manner to respond to groundwater contamination at the Duke Energy Carolinas ash basins and address closure of those basins?
MS. TOWNSEND: Objection.
THE WITNESS: I don't have any basis to formulate an opinion about that.
BY MR. MEHTA:
Q. Do you know what the role of the public staff is?
MS. TOWNSEND: Objection.
THE WITNESS: I think generally I do, but I don't know all the specifics that they do.
BY MR. MEHTA:
Q. Just generally what is the role of the public staff?
A. Well, in the case of Utilities Commission, you know, these rate cases is to evaluate the rate -- the rate requests that have been made, you know, from I guess the public standpoint.
Q. So from the standpoint of the consumers of electric power?
A. That's my understanding, yes.
Q. Customers of the electric power company?

A. Yes, that's my understanding. Yes.
Q. Is the public staff, in your understanding, interested in raising the cost of electric power and it's not necessary to raise the cost of electric power?
MS. TOWNSEND: Objection.
THE WITNESS: I don't have a way to formulate an opinion about that. I don't know. I mean, I would guess not.
BY MR. MEHTA:
Q. What do you think?
A. I would guess that their role would be -- that they don't want to increase the risk, in general. Unless it's reasonable and necessary.
Q. There's some reason to do it? Unless there's some reason to do it, they're really not interested in just raising people's electric rates, correct?
MS. TOWNSEND: Objection.
THE WITNESS: Not just -- yeah, not just for some -- other than just I want to raise people's rates. There needs to be some reason to do it, yes.
BY MR. MEHTA:
Q. Skip over, if you would, Mr. Hart, to pages --let's see. I guess starting on page 126 through the end of your testimony.
A. Okay.

Q. We're really reaching the second of the two questions that you started with, right?
A. Yes. That's correct.
Q. And on page 127, I guess I'm looking at lines eight through 12.
A. Okay.
Q. Concerning the guilty plea. And you indicate that the guilty plea in how it managed some sites likely prompted a lack of confidence by regulators and the public. Do you see that?
A. Yes.
Q. What is the basis of making that statement?
A. Well, I think, for example, the CAMA amendments where they -- with regard to the water supply well connections for anyone within a half mile radius, regardless of whether they had contamination or not or their relation to the contamination boundaries is an extraordinary step and that clearly was, in my opinion, because there was a lack of confidence that DEQ was going to address the groundwater contamination issues and deal with them.
Q. So in connection with -- there's another likely down at the bottom of the page, but we'll use them both in conjunction. Did you do any surveys of regulators or the public to understand whether they likely had a lack of

confidence in Duke Energy Carolinas to perform what it should perform?
A. No, we did not.
Q. Is that something you could do, could have done?
A. Well, potentially. I know from talking to the DEQ people, they have real concerns about talking about any of this to us because of the ongoing issues that, I guess, had recently been -- with regards to DEC suing DEQ about -- whatever the legal mechanism is for not approving their closure plans and requiring excavation. And so, you know, some of the folks when we talked to them at the Winston-Salem region office said they could provide us the documents but they were -- even at first they said they didn't want to provide us the documents. That they felt that they were still under some -- we can't discuss this issue.
Q. Litigation has all been resolved, has it not?
MS. TOWNSEND: Objection.
THE WITNESS: I don't know.
BY MR. MEHTA:
Q. Well, you knew that the matter had been settled, correct?
A. Yes. I think it was, you know, around the time that we were doing our investigation. I'm not sure what

the date was.
Q. Well, did you go back to them after you understood it was settled to say I need to interview you to figure out whether whatever DEC did prompted a lack of confidence on your part?
MS. TOWNSEND: Objection.
THE WITNESS: Not specifically, no.
BY MR. MEHTA:
Q. Is there anything that prevented you from surveying the public to see if they lacked confidence in DEC?
MS. TOWNSEND: Objection.
THE WITNESS: I mean, certainly I was -- you know, I was part of the public during that time frame. And I'm aware that there was a number of groups like Sierra Club and some of these others that had expressed concern about the ability to make sure this didn't happen again and whether, you know, it could be a trust issue, I guess. But I -- you know, I didn't go out and survey the public, no.
BY MR. MEHTA:
Q. Why not? If you're going to make a statement that the public lacked confidence, why wouldn't you survey the public?
MS. TOWNSEND: Objection.

THE WITNESS: Well, again, you know, this was something that I experienced directly in, you know, newspaper articles and all those kind of things to speak to the fact that there were real concerns about this issue.
BY MR. MEHTA:
Q. So do you equate your personal feelings of lack of confidence to the public?
MS. TOWNSEND: Objection.
THE WITNESS: Well, it wasn't just my personal feelings. It was expressed in other areas as well.
BY MR. MEHTA:
Q. Do you conflate the expressions in newspapers to lack of confidence by the public?
MS. TOWNSEND: Objection.
THE WITNESS: It could be, depending on the article, certainly.
BY MR. MEHTA:
Q. If you really want to understand what the public thinks of a particular issue, are there systematic ways to go about figuring out what the public thinks about a public issue?
A. There could be. I think it's hard to do in a retrospective case. What did you think in 2014 about

this. I think that's difficult to do because there's information since then.
Q. Well, did you attempt to do anything systematic to validate this supposed lack of confidence by the public in Duke Energy Carolinas?
A. Not other than my experience and my experiencing the issues when they occurred.
Q. Are you -- do you hold yourself out to be an expert in divining the public will?
MS. TOWNSEND: Objection.
THE WITNESS: No.
BY MR. MEHTA:
Q. Do you hold yourself out as an expert in divining public sentiment?
MS. TOWNSEND: Objection.
THE WITNESS: No.
BY MR. MEHTA:
Q. Did you take any action to interview legislators about their view in terms of their confidence or lack thereof in DEC either at the time of the original CAMA or the amendments to CAMA?
A. No.
MR. MEHTA: Why don't we take just a quick break and I think we'll wrap up fairly shortly.
VIDEOGRAPHER: We're off the record at

3:27 p.m.
- - -
(A break was taken.)
- - -
VIDEOGRAPHER: We're back on the record at 3:32 p.m.
BY MR. MEHTA:
Q. Mr. Hart, I will read you a statement and ask if you agree or disagree with it.
A. Okay.
Q. Here's the statement. It also includes the word company, in this case we're talking about Duke Energy Carolinas.
A. Okay.
Q. Had the company's management of coal combustion waste resulted in no exceedances of the state's to well groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits, the company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR rule and CAMA.
Do you agree or disagree with that statement?
MS. TOWNSEND: Objection.
THE WITNESS: I don't know. It would be -- it would have to be a facility-specific basis, I think.

BY MR. MEHTA:
Q. So you're not able to tell me, except on a facility-specific basis, if there had been no exceedances of the 2L standards, no violations of any permits, no criminal prosecutions, no lawsuits, if the company would have been required to undertake many or even most of the ash disposal activities now required of it by the CCR rule and CAMA?
MS. TOWNSEND: Again, same objection.
THE WITNESS: You're talking about ash disposal practices?
BY MR. MEHTA:
Q. Ash disposal activities. I would say the things that it is now required to do under the CCR rule and CAMA would have been required even though or even if there had been no exceedances of the 2L standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits.
MS. TOWNSEND: Same objection.
THE WITNESS: Well, I think it's certainly possible but for Dan River that CAMA would not have been passed and it would have gone to the federal CCR rules, which has a different set of criteria than the state's CAMA rules in some cases to allow in-place closure, if it met certain restrictions, height restrictions above the

water table, if there's no groundwater contamination. So it's very possible that if it was just the CCR rules, then some of these activities would not have been required or would not be undertaken right now.
BY MR. MEHTA:
Q. Well, the CCR rule is essentially enforced through state enforcement agencies, is it not?
MS. TOWNSEND: Objection.
THE WITNESS: Yes.
BY MR. MEHTA:
Q. And the state enforcement agency in this state is the DEQ, is it not?
A. Yes.
Q. And the state enforcement agency for CAMA is the DEQ, is it not?
A. Yes. But if you could show that there was no groundwater contamination from these basins and they weren't causing any environmental degradation, and they met the restrictions, you could certainly conclude that DEQ -- say these days basins can be closed in place or these basins can still be operating. The issue was the contamination they caused and then the release that happened.
Q. I understand that that is the position of the attorney general in this case. I think other parties

including DEC might have a different position. But let me try it one more time. Maybe the answer is I'm really not able to make the determination. But had the company's management of coal combustion waste resulted in no exceedances of the 2L standards, no violation of any permits, no prosecutions, no lawsuits, would the company eventually have been required to undertake many, if not even most, of the compliance requirements now required of it by the DEQ under both CAMA and the CCR rule?
MS. TOWNSEND: Objection. Asked and answered.
THE WITNESS: I don't believe so. Not -- potentially, no. Can't say with certainty.
BY MR. MEHTA:
Q. You can't say with certainty why?
A. Because you're asking a hypothetical. It doesn't exist.
Q. And is the parts of it that you have trouble with the no exceedances, no violations, or is it that the activities would be the same regardless?
MS. TOWNSEND: Objection.
THE WITNESS: No, I think if -- but for the Dan River spill, I don't believe CAMA -- it's a possibility that CAMA would have been passed and there, like many states, would have been -- addressing these

company ash monitors would have been under the CCR rules, which don't necessarily require excavation if certain requirements are met. So if you're saying there's no groundwater contamination, there's no, you know, problems with these basins, then certainly you could have made a reasonable case that these could have been closed in place. Because there's no contamination. Why not close in place? It's not going to get worse after you close them. It's going to get better.
BY MR. MEHTA:
Q. In terms of other states that don't have CAMA, South Carolina for example, South Carolina is in fact requiring all of its coal ash basins to be excavated, is it not?
MS. TOWNSEND: Objection.
THE WITNESS: Well, I'm not fully familiar with that. But I believe that's as a result of a settlement between SELC and State of South Carolina and the energy companies down there. But there are certainly other states where in-place closure is allowed.
BY MR. MEHTA:
Q. And the State of Virginia or the Commonwealth of Virginia is requiring all of the coal ash basins to be excavated, is it not?
MS. TOWNSEND: Objection.

THE WITNESS: I don't know that. But I think it's because of the contamination issues. So you're asking me if there wasn't any contamination issues, assume that, then I don't think there would be a problem.

MR. MEHTA: Mr. Hart, that's all I have for you today. I will say though that since I have requested the work papers associated with the whatever time value of money calculations that Mr. Hart has made, I'm going to reserve the right to ask him some more questions related to that.

VIDEOGRAPHER: Go off the record real quick?

MS. TOWNSEND: Yes, please.

VIDEOGRAPHER: We're off the record at 3:42 p.m.

\- - -

(A break was taken.)

\- - -

VIDEOGRAPHER: We are back on the record at 3:43 p.m.

MS. TOWNSEND: Okay. In response to your request for the work papers, we will provide those to you as soon as we have them in our hands.

MR. MEHTA: Thank you very much.

VIDEOGRAPHER: This concludes the

deposition. We're off the record at 3:43 p.m.

(Proceedings concluded at 3:43 p.m.)

CERTIFICATE OF REPORTER

I, Susan A. Hurrey, Registered Professional Reporter and Notary Public for the State of North Carolina at Large, do hereby certify that the foregoing transcript of Steven C. Hart, taken March 2, 2020, is a true, accurate, and complete record.

I further certify that I am neither related to nor counsel for any party to the cause pending or interested in the events thereof.

Witness my hand this 5th day of March, 2020 at Burlington, Alamance County, North Carolina.

Susan A. Hurrey, RPR
My Commission expires
September 24, 2023

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
DOCKET NO. E-7, SUB 1214

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of)
Application of Duke Energy)
Carolinas, LLC for Adjustment)
of Rates and Charges Applicable)
to Electric Service in North)
Carolina)

DEPOSITION OF STEVEN C. HART
CERTIFICATE OF DEPONENT

I hereby certify that I was first duly sworn prior to my deposition, and that after reviewing the transcript, I request (CIRCLE ONE):

(a) no changes to the transcript, OR
(b) that the changes noted on the accompanying errata sheet be incorporated into the transcript.

____
Steven C. Hart

Witness, my hand and seal, on this, the _______ day of _________________, 2020.

____
Notary Public

My Commission Expires: _______________

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
DOCKET NO. E-7, SUB 1214

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of)
Application of Duke Energy)
Carolinas, LLC for Adjustment)
of Rates and Charges Applicable)
to Electric Service in North)
Carolina)

DEPOSITION OF STEVEN C. HART
ERRATA SHEET

PAGE LINE SHOULD READ REASON FOR CHANGE

Signed this the _____ day of _________________, 2020.

____
Steven C. Hart

North Carolina

Utilities Commission

What does the NC Utilities Commission Regulate?

Electricity	
NCUC Regulates	**NCUC Does Not Regulate**
Investor-Owned electric companies including: **Dominion Energy North Carolina** **Duke Energy Carolinas** **Duke Energy Progress** • Rates and charges • Meter and billing accuracy • Reliability of electric service • Quality of service • Need for new power plants and large power lines • Routes for new large power lines • Conservation and renewable energy programs • Resellers of electricity • Disconnection of service • Renewable energy facilities **To a limited degree, the NCUC also regulates:** **Resellers of electricity** **Renewable energy facilities**	**Municipally-owned utilities and electric membership corporations (cooperatives)** The NCUC does not regulate: • Electrical wiring inside customer's home • Damage claims, such as food spoilage from power outages • Eminent domain decisions or payments • Coal ash storage or disposal • Air or water emissions from power plants
Natural Gas	
NCUC Regulates	**NCUC Does Not Regulate**

SETTLEMENT AGREEMENT

This is an AGREEMENT TO SETTLE AND FOR RELEASE OF CLAIMS "Agreement") made and entered by and among North Carolina Department of Environmental Quality ("DEQ") (formerly known as the North Carolina Department of Environment and Natural Resources) on the one hand, and Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (formerly known as Duke Energy Progress, Inc.) (together, "Duke Energy") on the other. DEQ and Duke Energy (collectively, the "Parties") agree to the following terms as a basis upon which to resolve the issues between them relating to alleged exceedances of state groundwater standards associated with coal ash facilities at sites operated by Duke Energy and its predecessors. By this Agreement, the undersigned settling Parties mutually agree to compromise, settle, and forgo all current, prior, and future claims related to exceedances of groundwater standards associated with coal ash facilities at Duke Energy's North Carolina facilities.

I. <u>RECITALS</u>

WHEREAS, Duke Energy owns and operates the following facilities that are the subject of this Agreement (collectively, the "Duke Energy Sites"):

(1) the Allen Steam Station, located in Gaston County;

(2) the Asheville Steam Electric Generating Plant, located in Buncombe County (the "Asheville Plant");

(3) the Belews Creek Steam Station ("Belews Creek Plant"), located in Stokes County;

(4) the Buck Steam Station, located in Rowan County, which has been retired and is no longer used for the production of electricity;

(5) the Cape Fear Steam Electric Generating Plant, located in Chatham County, which has been retired and is no longer used for the production of electricity;

(6) the Dan River Steam Station, located in Rockingham County, which has been retired and is no longer used for the production of electricity;;

(7) the H.F. Lee Steam Electric Generating Plant ("H.F. Lee Plant"), located in Wayne County, which has been retired and is no longer used for the production of electricity;

(8) the Marshall Steam Station, located in Catawba County;

(9) the Mayo Steam Electric Generating Plant, located in Person County;

(10) the Riverbend Steam Station, located in Gaston County, which has been retired and is no longer used for the production of electricity;

(11) the Rogers Energy Complex (formerly Cliffside Steam Station), located in Cleveland and Rutherford Counties;

(12) the Roxboro Steam Electric Generating Plant in Person County;

(13) the L.V. Sutton Electric Plant, located in New Hanover County (the "Sutton Plant"), which has been retired and is no longer used for the production of electricity; and,

(14) the Weatherspoon Steam Electric Plant, located in Robeson County, which has been retired and is no longer used for the production of electricity.

WHEREAS, the National Pollutant Discharge Elimination System ("NPDES") Permits associated with the Duke Energy Sites contain requirements for Duke Energy to monitor groundwater at the Duke Energy Sites and to report the results to DEQ.

WHEREAS, Duke Energy has at all times complied with its groundwater monitoring and reporting requirements of its NPDES Permits for each of the Duke Energy Sites.

WHEREAS, on June 17, 2011, DEQ issued its "Policy for Compliance Evaluations of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirement" (hereinafter, the "2011 Policy for Compliance Evaluations"). The 2011 Policy for Compliance Evaluations attempts to address the situation where groundwater monitoring indicates that a "long-term permitted facility" is out of compliance with the 2L standards, including the conditions under which DENR might issue a NOV to the affected facility.

WHEREAS, the 2011 Policy for Compliance Evaluations includes a detailed flow chart dictating the steps to be taken by DEQ should Duke Energy report any exceedance of North Carolina's groundwater standards as established pursuant to N.C.G.S. Chapter 143 and 15A N.C.A.C. Subchapter 2L at the Duke Energy Sites. Those steps include, but are not limited to: (1) verify the accuracy and significance of the results of the groundwater testing; (2) determine whether and to what extent the identified substance could be naturally occurring; and, (3) evaluate other possible sources of the identified substance.

WHEREAS, on August 26, 2014, DEQ sent Duke Energy a Notice of Violation based upon the exceedances of the State's groundwater standards reported to DEQ for the Sutton Plant (the "Sutton NOV").

WHEREAS, on September 20, 2014, the North Carolina Coal Ash Management Act ("CAMA") became effective. CAMA requires, among other actions, closure and dewatering of all ash ponds at the Duke Energy Sites and dictates, in detail, a procedure for assessing, monitoring and where appropriate, remediating groundwater quality in areas around coal ash impoundments in North Carolina that follows closely the procedures outlined in DEQ's 2011 Policy for Compliance Evaluations.

WHEREAS, Duke Energy submitted monitoring that showed exceedances of the State's groundwater standards at or beyond the compliance boundary at the Asheville Plant.

WHEREAS, on February 25, 2015, DEQ sent Duke Energy a Notice of Violation, this one based upon groundwater monitoring results reported to DEQ for the Asheville Plant (the "Asheville NOV").

WHEREAS, on March 10, 2015, DEQ assessed a $25.1 million civil penalty (the "Penalty Assessment") against Duke Energy based upon groundwater monitoring results reported to DEQ for the Sutton Plant.

WHEREAS, on April 9, 2015, Duke Energy filed a Petition for Contested Case at the North Carolina Office of Administrative Hearings, challenging the Penalty Assessment on multiple legal and factual grounds (the "Sutton Petition").

WHEREAS, the Parties have engaged in extensive discovery regarding the arguments raised in the Sutton Petition, during which the Parties have concluded that:

(1) The 2011 Policy for Compliance Evaluations is a current DEQ policy that was in effect at the time DEQ issued the Sutton NOV, the Asheville NOV and Penalty Assessment against Duke Energy;

(2) The 2011 Policy for Compliance Evaluations applies to each of the Duke Energy Sites listed above;

(3) The 2011 Policy for Compliance Evaluations states that as "long as the permittee is cooperative with the Division in taking the necessary steps to bring the facility into compliance, a notice of violation may not be necessary."

(4) During the discovery process internal e-mails and testimony by former DENR management demonstrate that, although not expressly stated in the 2011 Policy for Compliance Evaluations, the intent at the time the 2011 Policy for Compliance Evaluations

was that corrective action would precede any enforcement and would be in lieu of monetary penalties.

WHEREAS, DEQ further acknowledges that the procedures outlined in CAMA are specifically designed to address, and will address, the assessment and corrective action of alleged groundwater contamination associated with coal ash facilities at the Duke Energy Sites. In combination with the specific requirements of CAMA, DEQ further acknowledges that this Agreement fully addresses and resolves all issues related to groundwater contamination associated with coal ash facilities at the Duke Energy Sites, including all groundwater violations alleged in the state enforcement actions currently pending in Superior Court in Wake and Mecklenburg Counties.

WHEREAS, DEQ and Duke Energy have determined that it is in the best interest of the Parties, the environment, as well as the citizens of North Carolina, that they enter into a compromise settlement to avoid the time and expense of prolonged litigation so that the Parties may focus the same on the assessment and, if necessary, corrective action of alleged groundwater standard exceedances at the Duke Energy Sites.

WHEREAS, DEQ and Duke Energy have determined that the actions provided for in this Agreement and the provisions of CAMA represent the best course for prompt assessment and remediation of any alleged groundwater standard exceedances at the Duke Energy Sites.

NOW, THEREFORE, in consideration of the promises and covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, DEQ and Duke Energy agree to compromise, settle, and dismiss with prejudice all claims and causes of action related to alleged groundwater standard exceedances associated with coal ash facilities at the Duke Energy Sites upon fulfillment of the terms and conditions set forth below:

II. DUKE ENERGY'S OBLIGATIONS

A. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Sutton Plant on the following terms and conditions:

(1) Duke Energy will commence installation of extraction wells on the eastern portion of the Sutton Plant property where data show constituents associated with the ash basins at concentrations over the 2L standards ("Constituents of Interest") have migrated off site.

(2) Extraction wells will be used to pump the groundwater to arrest the off-site extent of the migration. The pumped groundwater will be treated as needed to meet standards and returned either to the ash basin or the discharge canal.

(3) This extraction and treatment system will be installed as soon as practicable following receipt of all permits and approvals from DEQ, the issuance of which will occur as soon as practicable. This accelerated groundwater remediation is in addition to and shall be performed concurrent with the coal ash impoundment closure obligations set forth in CAMA.

(4) The extraction wells shall remain operational until such time as Duke Energy demonstrates through sampling, analysis, and appropriate modeling, and subject to DEQ's written concurrence, that off-property constituents of interest have been remediated to 2L Standards and there is no reasonable potential for future off-site migration.

(5) As part of accelerated remediation, DEQ agrees that dry ash can be removed from the head of the ash basins under a construction storm water permit and shall expedite such construction storm water permit in order for Duke Energy to commence the removal of ash which is the source of the constituents of interest from the Sutton Plant. DEQ will issue construction storm water permits for Sutton plant within 10 days of receiving Duke Energy's complete application. Only dry ash from the head of the ash basins will be removed with no impact to wastewater treatment or water levels in the basins. DEQ shall use its best efforts to complete the process of the issuance of the NPDES permit modification at the Sutton Plant to allow for the removal of water and ash beyond the areas covered under the construction storm water permit from the Sutton Plant.

B. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Asheville Plant, Belews Creek Plant, and H.F. Lee Plant, which are the only three other Duke Energy facilities that demonstrated offsite groundwater impacts in isolated areas that are not impacting private wells in the Comprehensive Site Assessments conducted pursuant to CAMA. Such accelerated remediation shall be tailored to each facility's unique characteristics.

C. Petitioner agrees to pay to Respondent the sum of seven million dollars ($7,000,000.00) (the "Payment") in full settlement of all current, prior, and future claims related to exceedances of groundwater standards associated with coal ash facilities at Duke Energy's North Carolina facilities. The Payment shall be made by check and made payable to the North Carolina Department of Environmental Quality and delivered to the following address:

North Carolina Department of Environmental Quality
Sam M. Hayes
217 West Jones Street
Raleigh, North Carolina 27603

The Payment shall be made within thirty (30) days of the receipt by Duke Energy of the acknowledgment described in part III.A. below. The Payment shall be accepted and acknowledged in writing by DEQ as "Payment In Full" in this matter within thirty-five (35) days of the execution of this Agreement.

D. Within fifteen (15) days of the receipt by Duke Energy of the acknowledgment described in part III.A. below, Duke Energy shall file and serve a Voluntary Withdrawal with Prejudice of the Sutton Petition, Case No. 15-EHR-02581, the Petition for Contested Case Hearing filed by Duke Energy related to the Notice of Regulatory Requirements dated July 9, 2014, Case No. 14-EHR-09631, and the Petition for Contested Case Hearing filed by Duke Energy related to the determination that Sutton Lake is waters of state, Case No. 15-EHR-04922.

III. DEQ'S OBLIGATIONS

A. Within five (5) days of the execution of this Agreement, DEQ shall communicate to Duke Energy, in writing, its withdrawal and rescission, with prejudice, of the Sutton NOV, the Sutton NORR, the Asheville NOV, and the Penalty Assessment.

B. DEQ shall not issue any further Notices of Violation, Notices of Regulatory Requirements, other similar notices, unilateral orders or civil penalty assessments to, file any judicial action against, or take any administrative, regulatory, or other enforcement actions against Duke Energy based on or in any way related to any previous or future groundwater monitoring results or alleged groundwater conditions at any of the coal ash facilities at any of the Duke Energy Sites, as long as Duke Energy continues to be in substantial compliance with CAMA requirements as they relate to groundwater assessment and remediation and closure of ash basins, including corrective action plans. DEQ also shall not issue Notices of Violation, Notices of Regulatory Requirements, other similar notices, unilateral orders or civil penalty assessments to, file any judicial action against, or take any administrative, regulatory, or other enforcement actions against Duke Energy based on or in any way related to the classification of Sutton Lake as waters of the State as set forth in paragraph II.D. above.

C. Except as necessary under CAMA or unless ordered or required to change, alter, modify, or amend by a court of competent jurisdiction or by the enactment or amendment of any applicable federal or state statute, rule, or regulation, or in response to an immediate threat to public health, DEQ agrees to not materially modify the groundwater monitoring terms in the existing NPDES Permits and in issuing future NPDES Permits for the Duke Energy Sites. For purposes of this provision "immediate threat to public health" shall mean circumstances beyond exceedances of the applicable provisions of 15A N.C.A.C. Subchapter 2L (the " 2L Standards"). Except as provided in part III.B above, DEQ further agrees to limit the use of the results of any groundwater monitoring required by NPDES permits or CAMA for the determination of prioritizing the coal ash impoundments and approving closure plans. This provision shall not modify the rights, duties and obligations of DEQ or Duke Energy pursuant to CAMA.

D. DEQ agrees that applicable, enforceable groundwater quality standards and naturally occurring (also known as "background") concentrations shall only be those established pursuant to applicable provisions of the " 2L Standards."

E. Duke Energy and DEQ acknowledge that Duke Energy has been receiving and may in the future continue to receive concerns from individuals or local governments regarding alleged adverse impacts to groundwater from beneficial re-use activities conducted under Distribution of Residual Solids Permits, Ash Reuse Permits or similar permits issued by DEQ or its predecessors authorizing ash reuse programs. Except as otherwise provided by CAMA and the Distribution of Residual Solids permits, Ash Reuse Permits, or similar permits issued by DEQ, DEQ shall be responsible for investigating (including, when necessary, collecting and analyzing groundwater samples) and respond to all such concerns and shall notify Duke Energy of all such responses.

F. DEQ will issue construction storm water permits for Sutton plant within 10 days of receiving Duke Energy's complete application. Only dry ash from the head of the ash basins will be removed with no impact to wastewater treatment or water levels in the basins. DEQ shall use its best efforts to complete the process of the issuance of the NPDES permit modification at the Sutton Plant to allow for the removal of water and ash beyond the areas covered under the construction storm water permit from the Sutton Plant.

IV. LEGAL PROVISIONS

A. Binding Nature of Agreement. The Parties represent and agree that the persons executing this Agreement have full and sufficient authority to sign and agree to be bound by the Agreement, and that this Agreement shall be binding upon DEQ and Duke Energy, and their successors and assigns, upon its execution by all Parties.

B. No Admissions. By entering into this Agreement, the Parties to this Agreement make no admission of liability, violation, or wrongdoing whatsoever, by itself, any of its affiliated companies, or any or its or their present or former officers, directors, employees, or agents.

C. Attorney's Fees, Costs, and Expenses. The Parties agree to bear their own respective attorney's fees, costs, and other expenses that have been incurred in connection with any stage of the state enforcement actions or Duke Energy's Petition for Contested Case related to the Penalty Assessment.

D. Governing Law and Interpretation. This Agreement shall be governed and interpreted in accordance with the laws of the State of North Carolina without regard to the conflict of laws provisions of North Carolina or any other state, and any provision herein that violates a statute or rule shall be void and unenforceable.

E. Enforceability and Remedies for Breach. The Parties stipulate and agree that this Agreement may be enforced in any court of competent jurisdiction in North Carolina, and that venue is appropriate in either Wake or Mecklenburg County. The Parties' sole and exclusive remedy for breach of this Agreement shall be an action for specific performance or injunction. In no event shall any Party be entitled to monetary damages for breach of this Agreement. In addition, no legal action for specific performance or injunction shall be brought or maintained until: (a) the non-breaching Party provides written notice to the allegedly breaching Party which explains with particularity the nature of the claimed breach, and (b) within thirty (30) days after receipt of said notice, the allegedly breaching Party fails to cure the claimed breach or, in the case of a claimed breach which cannot be reasonably remedied within a thirty (30) day period, the allegedly breaching Party fails to commence to cure the claimed breach within such thirty (30) day period, and thereafter diligently completes the activities reasonably necessary to remedy the claimed breach. This Agreement may be introduced as evidence in any action involving either or both Parties for the purpose of implementing its terms.

F. Severability. The invalidity or unenforceability of any provision of this Agreement shall in no way affect the validity or enforceability of any other provision; the invalid or unenforceable provision shall be stricken, without assessing damages or imposing penalties to either Party arising out of said provisions by any court of competent jurisdiction.

G. Headings. The headings used in this Agreement are for convenience of reference only and shall in no way define, limit, expand or otherwise affect the meaning of any provision of this Agreement.

H. Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument.

I. Amendment. This Agreement may not be modified, altered or changed except in a written document that is signed by all Parties and that makes specific reference to this Agreement.

J. Entire Agreement. This Agreement sets forth the entire agreement between the Parties, and fully supersedes any prior agreements or understandings between the Parties related to the subject matter of this Agreement, including but not limited to alleged groundwater standard exceedances associated with coal ash ponds at the Duke Energy Sites.

K. Review and Signing. Each Party and counsel for each Party has reviewed this Agreement. Accordingly, this Agreement shall be construed without regard to any presumption or other rule of construction requiring resolution of ambiguities against the drafting Party.

L. The Parties agree that this Agreement does not affect in any way the Joint Enforcement Agreement between DEQ and U.S. EPA, the subject of which does not involve any alleged groundwater standard exceedances associated with coal ash facilities at the Duke Energy Sites.

[Signature page follows]

IN WITNESS WHEREOF, DEQ and Duke Energy, and their respective counsel have executed this Agreement as of September 29, 2015.

NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY

By: ______________________

Its: General Counsel

Date: 9/29/15

KILPATRICK TOWNSEND & STOCKTON LLP

By: ______________________

Its: ______________________

Date: 9/29/2015

DUKE ENERGY CAROLINAS, LLC

By: ______________________

Its: Associate General Counsel

Date: 9/29/2015

DUKE ENERGY PROGRESS, LLC

By: ______________________

Its: Associate General Counsel

Date: 9/29/2015

McGUIREWOODS LLP

By: ______________________

Date: 9/29/15

STATE OF NORTH CAROLINA

COUNTY OF WAKE

IN THE OFFICE OF
ADMINISTRATIVE HEARINGS
15 EHR 02581

DUKE ENERGY PROGRESS, INC.,)
)
Petitioner,)
)
vs.)
)
N.C. DEPARTMENT OF ENVIRONMENT)
AND NATURAL RESOURCES,)
DIVISION OF WATER RESOURCES,)
)
Respondent.)
_ _ _ _ _ _ _ _ _ _ _ _ _ _ _ _)

VIDEOTAPED DEPOSITION

OF

COLEEN SULLINS

At Raleigh, North Carolina
August 24, 2015 - 9:07 a.m.

Reported by:
Marian E. Cummings, LSR

capitalreporting

PO Box 17943
Raleigh, NC 27619

3509 Haworth Drive, Suite 403
Raleigh, NC 27609

919.841.4150 ph
919.741.4122 fax

www.capreporting.com

main@capreporting.com

A P P E A R A N C E S

FOR THE PETITIONER:

Mark E. Anderson
McGUIREWOODS
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601
(919) 755-6600
manderson@mcguirewoods.com

Michelle S. Spak
DUKE ENERGY
550 South Tyron Street
Charlotte, North Carolina 28202

FOR THE RESPONDENT:

Clay C. Wheeler
Todd S. Roessler
KILPATRICK TOWNSEND
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609
(919) 420-1700
cwheeler@kilpatricktownsend.com
troessler@kilpatricktownsend.com

A P P E A R A N C E S, cont'd

FOR THE WITNESS:

Stephen T. Smith
McMILLAN & SMITH
205 W. Martin Street
Raleigh, North Carolina 27601
(919) 821-5124
smith@mspraleigh.com

ALSO PRESENT:

Michael Kirby, Videographer
C. Michael Beboud

T A B L E O F C O N T E N T S

[PREVIOUSLY MARKED EXHIBITS 5, 8, 25, 47 AND 50 ARE ATTACHED TO TRANSCRIPT]

I, Marian E. Cummings, LSR, being a court reporter and a Notary Public in and for the state of North Carolina, was appointed commissioner by consent to record the deposition of COLEEN SULLINS on August 24, 2015 beginning at 9:07 a.m., at the offices of Kilpatrick Townsend, located at 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina.

____

THE VIDEOGRAPHER: We're on the record at 9:07 a.m. This is the videotape deposition of Coleen Sullins. This deposition is being held in the offices of Kilpatrick, Townsend and Stockton, LLP located in Raleigh, North Carolina on August 24th, 2015.

The court reporter is Marian Cummings. The videographer is Michael Kirby, both with Capital Reporting. Would counsel please introduce themselves.

MR. WHEELER: Clay Wheeler for NCDENR.

MR. ROESSLER: Todd Roessler with NCDENR.

MR. ANDERSON: Mark Anderson on behalf of Duke Energy Progress.

MR. SMITH: And Steve Smith for Miss Sullins.

THE VIDEOGRAPHER: Would the court reporter please swear the witness.

Whereupon,

COLEEN SULLINS,

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

DIRECT EXAMINATION

BY MR. WHEELER:

Q. Hi Ms. Sullins. Good morning.

A. Good morning.

Q. As you know, my name is Clay Wheeler. I'm going to be taking yor deposition today. We've spoken once before and you met Todd Roessler who is another attorney with my firm.

Miss Sullins, have you been deposed before?

A. Yes.

Q. And in what case or controversy was that?

A. Multiple cases. The one that is most recent in memory is the Alcoa case.

Q. And were you deposed in connection with your employment at DENR?

A. Yes.

Q. If you had to just estimate how many times you've been deposed, what would you say?

A. I really don't recall.

Q. More than five?

A. Yes.

Q. This is not a new environment for you?

A. It is not.

Q. So as you know, I'll be asking questions and Miss Cummings here will be recording your answers. As you also have heard probably countless times before it's important to speak up and speak clearly so she can understand what you're saying.

Non verbal gestures don't really work in a deposition, as you know, since she's creating a transcript so I'd appreciate your help with that.

If I say something that is confusing or you don't understand, please let me know and I will rephrase it. My questioning is okay, but not perfect so I'd ask you to allow me to try to change something if you don't understand what I'm saying.

A. Okay.

Q. And you know that there's water and coffee in here. You're welcome to get up any time and do that while we're on the record or off the record, you can take a break at any time you'd like, if you want to talk to your attorney.

The only thing I ask is if we're in the middle of the question you answer the question and then take that break; does that make sense?

A. I'll do my best.

MR. SMITH: One note on that, she has a medical issue that may require her to call for a break quickly.

MR. WHEELER: Absolutely.

MR. SMITH: And if she does, she'll try to make that so that it does not come at the end of your question before her answer.

BY MR. WHEELER:

Q. Of course. Just let us know as soon as you need to take that break. And another thing that I'd ask, Miss Sullins, is if you give me an answer, and sometimes this happens. I think I know some of these events are several years ago and in the course of later questioning you remember something that might help to clarify an answer you gave or add to an answer you gave, please go ahead and do that.

I'd ask that you so that if you are refreshed on things later on in the deposition we can make sure we just have complete answers; does that make sense?

A. Okay.

Q. Mr. Smith mentioned a medical condition. Is anything, any medication or drugs that might make it difficult for you to understand or answer my questions today?

A. No.

Q. Okay. Is there any other reason why we can't understand each other here today?

A. Not that I'm aware of.

Q. Okay. All right, on your side.

So Miss Sullins, what is your current address? Is it the address to which the subpoena was directed?

A. Yes, it is.

Q. The Dare Street?

A. 1605 Dare Street in Raleigh, North Carolina.

Q. How long have you lived at that address?

A. Almost 18 years.

Q. And what is your educational background?

A. I have a bachelor of environmental engineering and environmental water resources engineering.

Q. And where did you obtain that degree?

A. Vanderbilt.

Q. Are you married?

A. No.

Q. Have you ever been married?

A. Yes.

Q. And what time did your marriage end, what year?

A. 1997, I believe.

Q. What is your current employment status?

A. I'm unemployed.

Q. And what was your last full-time employment?

A. Director of the Division of Water Quality.

Q. At DENR; is that right?

A. Yes.

Q. When did you leave that employment?

A. December 2011.

Q. You're smiling as you say that. Why are you smiling?

A. I am. It's been a while.

Q. And have you had any employment since that time, any part-time employment?

A. I did some consultation for the Department and the AG's office for the litigation on the mine, PCS mine.

Q. Was that one of those occasions where you had to do a deposition?

A. I did not.

Q. So we're really -- I want to -- we're really going to be talking about your time at DENR here and please just assume that all of my questions have to do with the time when you were at DENRs as opposed to after you left; does that make sense?

Otherwise, I don't want to -- I'm not going to really be asking you about things that have happened recently since you've left unless I tell you I am, okay? I think that will make things easier.

A. Okay.

Q. What year were you born, Miss Sullins?

A. 1960.

Q. So when did you join -- what year did you graduate from college?

A. 1984.

Q. And when did you join DENR?

A. 1990.

Q. And when you joined DENR, what was your position?

A. I was an engineer in the Division of Water Resources.

Q. Was that here in Raleigh?

A. Yes.

Q. And how long did you hold that position?

A. Six months.

Q. And what happened to make you leave that position?

A. I moved to the Division of Water Quality to another position.

Q. What position was that?

A. I don't recall the title of it. I was responsible for the storm water programs for the State.

Q. Now, at the time, Miss Sullins, what was the relationship between the Division of Water Resources and the Division of Water Quality?

A. They were two separate entities that had very different responsibilities involving -- both of them involving water.

Q. So is it accurate to say they're two different silos in the department?

A. Yes, that is accurate to say.

Q. And how long were you in the Division of Water Quality?

A. I was in the Division of Water Quality until I retired at the end of December of 2011.

Q. And you said you went into the -- working on the storm water program when you first went to DWQ?

A. Yes, sir.

Q. Do you remember what your position was called?

A. I'm uncertain as to whether it was a supervisory position or whether it was another engineer position; I don't recall.

Q. How long did you have that position?

A. Until 1992.

Q. And then what happened?

A. I was promoted to the supervisor of the National Pollutant Discharge Elimination System Permitting Program.

Q. And that's again within the Department of Water Quality?

A. The Division of Water Quality, yes.

Q. Division of Water Quality, excuse me. And what was your -- what was that -- what did that job entail?

A. It was the position that oversaw the staff who issued permits for -- NPDES permits for waste water discharges.

Q. And how long did you work on those permitting issues?

A. I would say, in truth, for the rest of my career. In that position I am uncertain of how long I was in that specific position.

Q. Is that because you moved up the ladder from there?

A. Yes, sir.

Q. So what did you do next?

A. I took on the position of the permits and engineering supervisor which included the land base permitting as well as the NPDES permitting, so any waste applied to the land and then anything permitted under the NPDES program, including storm water and waste water.

And from there I moved to a position that was very short term, and I don't have my resume with me and I have to look at it to recall all the disparate pieces that were included in that, but it included some planning functions and from there I moved to the section chief for the water quality section which oversaw the permitting programs, the planning programs, the environmental sciences which were the field operations that went out and evaluated field conditions, and the regional offices, the portion of the regional offices that reported to the water quality section separate from the groundwater section. And from there I moved to the --

Q. Let me slow you down there, sorry. What year was that did you become the section chief?

A. I became the section chief in, I believe it was February of 1998.

Q. Okay. And then you were saying, you were answering a question I was going to ask which is as that section chief so you weren't directly involved with aquifer protection issues?

A. No, I was not.

Q. Okay, because again, those are under a different silo?

A. That's correct, a different silo within the division.

Q. Right.

A. But yes, I was not responsible for that.

Q. Okay. Well, that's a good point. So aquifer protection is within which -- is still within water quality?

A. That's correct.

Q. All right. And so when did you first -- was it when -- well, I'll just ask, when did you first gain supervisory control, if you will, over those kinds of issues?

A. When I moved to the deputy director position of the Division of Water Quality.

Q. When was that, roughly?

A. I believe that was April of 2004.

Q. And then when did you become director?

A. June of 2007.

Q. Let me ask you one question that just occurred to me; in your depositions that you've done as a former employee of DENR, as a current employee of DENR, was ever there any litigation involving a utility?

A. I don't recall.

Q. Okay.

A. It's possible.

Q. All right, but you don't remember if there was or not?

A. I do not recall.

Q. All right. So deputy director starting in April of 2004 and then June of 2007 you become the director; is that correct?

A. That is correct.

Q. Tell me as director what your responsibilities -- how you saw your responsibilities or what your responsibilities were.

A. My responsibilities were to manage the program and provide the staff the ability to do the things that they needed to do. I was responsible for reporting to the, not just the Department, but the Commission and carrying out the responsibilities and issues that they directed that I carry out.

Q. And when you say Commission, you're referring to the Environmental Management Commission?

A. I am.

Q. Can you explain just briefly, Miss Sullins, what that meant? I mean, what was the responsibility of the EMC?

A. The Environmental Management Commission had the responsibility for implementing or for developing and issuing rules associated with the statutory requirements for the water quality programs for the State. It was broader than just water quality. It was also air quality and it involved multiple divisions.

They also oversaw the planning functions and approved plans associated with the plans associated with addressing water quality issues. They got involved in variance type of issues.

They oversaw cases that came before them from the administrative law judge. When a decision was made, it was a recommended decision by the administrative law judge and then those decisions went before the Commission.

Q. Was that true of any enforcement that DENR had undertaken?

A. It was true of enforcement actions that entities chose to appeal.

Q. Right.

A. But otherwise, no. If they weren't appealed, then those decisions would be final.

Q. Right, okay. And did the -- were

aquifer issues within the EMC's, you know --

A. Yes.

Q. -- scope of responsibilities? So let's focus in now -- well, let me ask you one other question. How did -- can you tell me as director what your responsibilities were for enforcement? If we just talk about enforcement, how did you get involved with enforcement?

A. It would depend on specific cases and whether the -- the staff were delegated the responsibility and the authority to make decisions for enforcement cases, for the most part. If they were significant cases, those decisions would rise to my level for evaluation.

I don't recall that I issued many enforcement actions. Most of the enforcement actions when I was the director were actually issued by the staff. I would provide them direction on, you know, how to make those decisions.

Q. So let me see if I can rephrase that. You mean you wouldn't get involved in a particular case, but you would give guidelines as to how to think about enforcement; is that what you're saying?

A. I would give guidelines as to how to think about enforcement. Occasionally I would get involved in specific cases.

Q. And when you talk about staff doing enforcement, are you talking about staff in Raleigh, are you talking about staff at the regional offices or both or --

A. Both.

Q. Okay. How did that work? You know, how did you figure out where enforcement was going to come from?

A. I don't recall the specifics of it. However, what I can say about that is that there were certain levels of enforcement that were approved to be issued out of the regional offices and then it moved from the regional offices up to the section chiefs would be responsible and take action for it and it moved up the chain progressively.

Q. Okay. You mentioned two things that I want to follow up on there. One is you said that you might get involved in significant enforcement issues and can you tell me a little bit more about what that means or how that was determined if something was significant or not? Is it sort of a case-by-case basis?

A. It is more of a case-by-case basis and for me to be able to provide a generic overview, I'm trying to remember if I even issued any enforcement decisions when I was the director. I would get consultations on enforcement cases where staff felt like they wanted to come brief me on them, but I don't actually recall issuing any enforcement cases myself.

Q. And when you say issue, you mean your signature acutally going on --

A. My signature on the document, that's correct.

Q. All right. What about the -- you mentioned different levels of enforcement. Can you explain that a little bit more? What are some of the possible levels?

A. Well, there are some very simple cases like people who don't submit their monitoring reports and they just need to be reminded. And there's a small fine associated with reminding them that they haven't been submitting their monitoring reports. Those would be issued out of the regional offices.

The staff in the central office would assist the regional offices by providing them reports from the data system as to who hadn't submitted monitoring reports, as to who had violated their permit limits.

So there would be some levels of permit limit violation that were also done at the regional office. And when they got above a certain level, those cases would be handled by the central office staff.

Q. Okay.

A. And various levels of supervision in the central office staff had various levels of responsibility for taking action.

Q. So maybe at one end of the spectrum we've got something like the failure to submit reports as one of these, and then can you give me an example of something at the other end of the spectrum?

A. We had a case, I don't remember the town, that had been discharging without a permit from their sewer system and knowingly doing so and not reporting and that case was assessed at the central office level.

It was a significant dollar amount. It was over a hundred thousand dollars, if I am remembering properly, and those types of decisions rose to the level of consultation with the director's office, typically, and you know issuance at a higher level in the central office than out at the regions.

Q. Okay. So let's focus in on the coal ash issue and Miss Sullins, can you tell me when you first, when the issue of coal ash first sort of came on your radar?

A. As the director?

Q. Well, no, actually just any time during your time at DENR.

A. Coal ash first came on my radar when I was a permit supervisor over the NPDES permitting program and in the permits and engineering supervisory position as well. Coal ash has been an issue that I dealt with for most of my career at the Division of Water Quality.

Q. How did it come up with respect to permits?

A. Well, as the --

Q. Back when you're talking about it.

A. Back when I'm talking about it?

Q. Yeah.

A. As the supervisor for storm water permitting and developing the storm water permitting program for the state of North Carolina back in 1990, we began to have the initial discussions of what -- who was subject to permitting and how to develop those permits.

Q. And when we're talking about coal ash, are we -- who are the potential actors that you were thinking about in terms of permitted entities? Are we just talking about the two big utilities or are there others?

A. I don't recall if any of the pulp and paper facilities had coal ash or not, but it was primarily the two power companies.

Q. And what actions were taken in connection with permitting with respect to coal ash by DENR?

A. We had to develop a whole permitting scheme for storm water associated with that. We also issued permits for the discharge from coal ash ponds because it's considered a waste water, so under the waste water permitting program we issued those. And when there was the Clean Smokestacks legislation, I believe I have the title of that legislation correct, there were discussions about how to deal with the waste byproduct from the clean smokestacks, whether to deal with it as a dry waste or to deal with it as a wet waste.

It ended up being a wet waste and those were permitted under the permitting program, the water permitting program.

Q. That's a lot. Hold on a second. So when was the first -- well, let me ask you this. Did your permitting of coal ash related issues follow -- how did groundwater fit into that?

A. Groundwater issues didn't really fit into the permitting of coal ash because there wasn't a mechanism within which they fit. So I don't know when groundwater monitoring initially began or what the initial discussions were about groundwater monitoring.

Q. Can you explain that just a little bit? What do you mean there was no mechanism; what does that mean?

A. There's not a federal mechanism. The permits that I was responsible for were the national pollutant discharge elimination system permits and there's a scope that that program covers, both storm water and waste water. The aquifer protection side of it was not part of that federal scope.

Q. Okay. So did you become aware at this point that there was -- that monitoring began of groundwater related to coal ash?

A. Yes, I couldn't tell you when that point was.

Q. Do you remember how you became aware of that?

A. I really don't recall the specifics of it.

Q. Okay.

A. Groundwater monitoring had been an issue for years before it cropped up as an issue that we were dealing with more holistically, if that makes sense.

Q. Well, let me just ask you, what do you mean by it had been an issue for years? You mean groundwater monitoring around coal ash ponds had been an issue for years?

A. We had had discussions about groundwater monitoring associated with coal ash when I was in permitting and responsible for permitting.

Q. Okay.

A. Again, the scope of the federal program didn't cover that environmental issue.

Q. And when you were in permitting, what's the time frame there?

A. 1992.

Q. Roughly the early 1990s?

A. The early 1990s.

Q. Okay. And tell me a little bit more about that. So there were discussions about having -- were there discussions with the utilities

about this or just this was internal to DENR?
A. I don't recall discussions with the utilities.
Q. Okay. So internal to DENR there were discussions about whether somehow there should -- groundwater monitoring should begin around these ponds; is that right?
A. No. There were discussions -- the discussions that I was involved in were discussions around whether groundwater monitoring should be a component of the NPDES permit.
Q. Got it, okay. And was that completely within DENR's control? Could DENR have added that as a requirement if they wanted to at that point?
A. That was the discussion we were having is whether the federal regulations gave us the authority to place that within the NPDES permits or not.
Q. And was a conclusion reached on that?
A. It was not placed in the NPDES permits.
Q. Because it concluded that the federal regulations wouldn't permit it?
A. Right, we wouldn't have the legal basis under the NPDES regulations to require it.
Q. Okay. What about when you began your

supervisory work over the aquifer issues? What's the first time you remember the groundwater issue coming up?

A. I don't recall when the spill in Tennessee was, but it would have been, I believe, following the spill in Tennessee when we started looking at coal ash more holistically in the state.

Q. What do you mean by that holistically?

A. There are multiple agencies that have responsibility for different components of coal ash in the state of North Carolina. There's the Division of Water Quality, now the Division of Water Resources that had responsibility for the waste water discharges, the storm water discharges, the aquifer protection side of the equation.

There's the Division of Land Resources. I don't know what it is currently that had responsibility for some of the dam safety aspects. There's the Division of Waste Management who had responsibility for landfills, the dry handling of coal ash. The sites are very complicated.

The Commission, not the EMC, the utilities commission also had some responsibility associated with the dam safety aspect of things so there were a lot of different agencies that were involved.

And following the coal ash spill in Tennessee, the State started evaluating that and I believe that would have been about 2008, but I'm not positive on that date.

Q. Yeah, so it was the spill in Tennessee that sort of triggered a reaction by DENR; is that accurate?

A. I would say that's accurate. There were other things that were happening associated with coal ash and I don't recall the timing of all these things. The federal government began looking at how they wanted to regulate coal ash in the dry form as a -- whether to regulate it as a hazardous waste or other materials.

I don't know the waste management side of the issues. In addition to all that, we had the Clean Smokestacks being implemented and so we had air quality also engaged in those issues.

Q. So at that time, were there -- had DENR taken any action with respect to coal ash or is what you're saying that this -- there was the previous, you know, the previous decade there was a discussion about the possibility of groundwater monitoring and, I'm sorry, I'm really focused on groundwater monitoring.

A. Right.

Q. And then was it your understanding that until the Tennessee Valley spill there hadn't been any other activity on that subject?

A. No, that's not my understanding, but I don't know the details of the groundwater monitoring that had gone on. I don't know the discussions that had been held between the utility companies and the aquifer protection staff about getting wells installed and beginning some initial evaluation.

Some of that had been done, but I don't -- I don't know the timing of that, when all that began. I was not involved in that.

Q. All right. So this wasn't a blank slate when the Tennessee Valley spill happened; is that correct?

A. Absolutely not.

Q. How would those discussions or whatever was going on have come to your attention? How would that work?

A. I'm not sure. I don't really even know how to answer that question.

Q. Well, let me try again. As I said, some of my questions need to be restated. You just said that you became aware at some point that there were discussions going on with utilities concerning groundwater monitoring before Tennessee Valley issue, right?

A. Yes.

Q. And I'm just asking how that happened, how that would bubble up, if you were, to you?

A. If there were issues between sections within the Division those typically would bubble up and we would have discussions with the section chiefs and their staff about issues.

Q. Like, for example, jurisdictional questions, who does what?

A. That is an example of the kind of things that we would discuss would be jurisdictional issues. There -- I mean, the power companies, we were constantly in interaction with them because we were issuing permits for them to do a variety of different things.

So you know, they were sort of always on the radar like a large, a large permitted entity would be and a complex permitted entity because it involved multiple divisions trying to figure out how to issue the various permits for which they had responsibility and deal with the various issues.

Q. And when we talk about utilities, are we talking about at that time Progress and Duke; are there others?

A. I don't remember if there were any other utilities specifically. Progress and Duke were the primary two that we were dealing with.

Q. All right. So before I asked my questions which were not so clear, we were talking about how DENR then -- there was a response to this Tennessee Valley issue; is that right?

A. That is correct.

Q. And so describe that response.

A. Well, there was a group of people were brought together to begin evaluating the sites in North Carolina. This may have been initiated at the department level. I -- and most likely it was.

Q. And I'm sorry, when you say initiated at the department level, you mean by the Secretary or what does that mean?

A. By the Secretary, Assistant Secretary because there were multiple divisions who had responsibility for different components of those sites and the permitting associated with those sites.

Q. And I'm sorry, I interrupted. What was the reaction; there started to be some effort to --

A. To evaluate what we knew and what information we had associated with them.

Q. And do you remember what the results of those efforts were?

A. Well, we began an inspection program to go out and look at all those sites. I think it was a joint inspection program. I don't remember when EPA got engaged. They certainly were. North Carolina was not -- did not have the best record, as I recall.

There was some reporting done nationally where they looked at the number of these facilities that existed in each state and North Carolina came out to have a large percentage of facilities in the country, respectively, associated with coal ash ponds.

So I remember that EPA was involved in that. The Commission was interested and asked us to report on things regularly with the coal ash, so we would pull together reports and take them before the Commission on a regular basis in terms of what activities were going on or what we had found, including what kind of information we had on groundwater monitoring.

Q. And what was -- do you remember what kind of information you did -- do you remember what you found when you asked those questions?

A. We had limited information on groundwater. We had -- the information was insufficient to decipher the source of groundwater contaminants. It was insufficient in relationship to the requirements associated with property lines.

Q. What was -- where did this data come from; do you remember?

A. It came from the -- the utility companies had the -- had put in some wells in response, I believe, to requests in part by the groundwater staff, aquifer protection staff.

Q. Sort of as a voluntary --

A. I believe it was done on a voluntary basis.

Q. And what did DENR do once it understood the fact that this data was insufficient?

A. We began to have conversations as a department about what kind of monitoring might be needed to clarify what the source of the contaminants might be.

Q. What were some possibilities? As you were having these conversations, what were some possibilities of sources that were discussed?

A. Ash ponds, landfills, you know, the activities that were occurring on site trying to separate out those various different sources to determine where the controls might be needed, if controls were needed.

Q. And do you remember what the result of that process was?

A. Well, we certainly were meeting in addition to meeting internal to the department. We were also meeting with the utility companies to talk about putting additional wells in.

Q. And did that happen?

A. I believe it did. This would have been right towards of the end of my tenure, so I don't recall the specifics of that.

Q. During your tenure, do you -- was there a time at which the data provided by the utilities was sufficient to determine cause; do you remember?

A. I don't believe we had a sufficient amount of data at that point in time.

Q. And that's at the time, end of 2011?

A. Yes. I don't remember the last time I actually saw the data or discussed it, but I know that that was one of the concerns and issues was collecting a sufficient amount of data to be able to interpret what the data was telling us.

Q. Other than collecting data, were you aware of any other actions being taken by Duke or Progress in connection with the groundwater issue?

A. I can't say that I am.

Q. Or I guess, do you recall that happening?

A. I really don't, don't recall any specifics there.

Q. Do you recall any notices of violation going out to Duke or Progress?

A. I really don't recall the notices of violation. They went out to the permitted community on a monthly basis. I don't recall any that were specific to Duke or Progress.

Q. You mean you think there may have been some, but you just don't remember or you think there probably were not?

MR. ANDERSON: Objection.

A. I have no idea. I just don't recall.

Q. Was this issue of groundwater -- groundwater monitoring in connection with coal ash, was that a significant issue?

A. Yes.

Q. Okay. If there had been a notice of violation in connection with that, do you think it would have stuck in your head? Just --

A. I -- you know, this was one issue that I dealt with in a division that had a lot of issues. I just don't really recall, recall that.

Q. All right, Miss Sullins, I want to show you a document. We're going to mark this as Exhibit Number 198.

[EXHIBIT 198 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. It's got a Bates number on it also produced by Duke in 11120. I've got copies for you guys.

So this is a letter dated March 3rd of 2009.

MR. SMITH: May she have a moment to review?

MR. WHEELER: Oh, please.

BY MR. WHEELER:

Q. Have you had a chance to look at it?

A. I have.

Q. Does it look familiar to you?

A. The issues are familiar. I don't recall this specific letter, but the issues are familiar.

Q. When something like this would go out and be cc'd to you, how would that normally be delivered to you, would you say? Was it a paper copy or did they do it by email?

A. It was a paper copy.

Q. Okay. And you had mentioned -- so this is March 3rd of 2009. You had mentioned that there came a time at which DENR started to look more carefully at data that it had from the utilities; is that accurate?

A. That is accurate.

Q. And does this timing seem about right to you as to when that might have happened?

A. This timing does seem about right to me.

Q. Okay. Now, if you look at the first paragraph, Miss Sullins, it says that the purpose of this monitoring, they're talking about voluntary groundwater monitoring and that's something that you had sort of referred to earlier?

A. Yes.

Q. The purpose is to help determine the environmental impact of coal ash storage; do you see that?

A. I do.

Q. And then the next sentence says "over the past two years we've received one or more reports containing data from six of your facilities that operate under NPDES permits." Was that what you were referring to as data that was being voluntarily provided to DENR?

A. Yes.

Q. Do you -- just as an initial question, do you know what was done with that data?

A. Well, the aquifer protection staff would have evaluated the data, but you know, in terms of what was done with it, I would say what was done with it is this letter asking for more clarification on the location of the monitoring wells in relationship to the various different things on site in an effort to determine where the wells were, what the information from the wells might actually be telling you.

I mean, without knowing where they are, upgradient, down gradient, from a waste source and what that waste source is and whether there might be intersecting plume from different waste sources, it's very difficult to interpret the data.

Q. The data you've been provided by the utilities was very difficult to interpret and that's why that sort of triggered this letter; is that accurate?

MR. ANDERSON: Objection.

A. I don't know that I can say that specifically. I can say that we needed further information in order to try and interpret the data that we had.

Q. Yeah. I mean, how can you interpret the data if you don't know where the wells are?

A. Exactly.

Q. So the well information was not provided in this data. Is that what seems to be suggested by this letter?

MR. ANDERSON: Objection.

A. I don't know what kind of information had been provided associated with the wells.

Q. Well, the letter requests to show the locations of all monitoring wells, right?

A. It does.

Q. Okay. So would a letter request that if they already had it?

MR. ANDERSON: Objection.

A. The letter requests the locations in relationship to waste boundaries, review boundaries, compliance boundaries trying to sort out what the different potential sources of the contamination, if contamination was seen in the data.

Q. And does that suggest that those locations were not known prior to this letter?

A. It certainly suggests that, yes.

Q. If you look at the second paragraph it refers to standard exceedances outside the allowable range. What does that mean?

A. There are water quality standards, groundwater quality standards, which are designed to protect health and biological communities and exceedances are just that; hey, if they exceed that particular standard, however with groundwater there are issues associated with compliance boundaries and review boundaries that have to be determined. An exceedance inside of those boundaries is not a violation of the standard.

Q. And when we're talking about standards, we're talking about what some people refer to as the 2L standards?

A. The groundwater standards, yes, sir.

Q. Do people refer it as a 2L standard sometimes?

A. They do.

Q. So you're saying I think -- is it similar to the point you were talking about earlier which is to understand whether the significance of an exceedance, you've got to know where the well is?

A. That's correct.

Q. And if the well is at a compliance boundary, what does that mean?

A. If the well is at a compliance boundary and there's an exceedance, then they have exceeded the groundwater standard.

Q. Is that a violation of the groundwater standards?

MR. ANDERSON: Objection.

A. Yes, I believe it would be.

Q. Do you know if this letter was sent by -- strike that. Let me start over again.

Who signed this letter?

A. Ted Bush.

Q. And who was Mr. Bush?

A. He was chief of the aquifer protection section.

Q. Was he a chief that reported to you at this time?

A. He reported to the director's office, which included me and the deputy director.

Q. Okay. And you had different chiefs reporting up into the director's office?

A. That is correct.

Q. How many, total, did you have?

A. There was the aquifer protection section, the water quality section, the environmental sciences section, the laboratory section, the business office. I think that's it.

Q. Okay. Is this -- do you think looking at this letter, is this the kind of thing you would have been involved in before it went out or is this more of a true cc to you?

A. This is more of a true cc to me.

Q. Okay. Let's look down. So you see there's a list of bullet points there. I think -- does it look like there's sort of a list of those are all requests that are being made on that first page?

A. Yes, those -- that's requested information that's being made.

Q. Okay. And so for example, the second one talks about maps; do you see that?

A. Yes.

Q. What about let's look at the bottom bullet point. And it asks for an evaluation to determine if the facility is in compliance. It includes things like well locations, determination of exceedances and planned action as a result of exceedances. Can you sort of tell me what -- as you read what that's requesting?

A. Well, it's requesting information on the well locations, so the waste boundary might be a landfill, it might be a coal ash facility, it might be some other type of waste facility on site. It's asking -- the well location is to be plotted in relationship to the review boundary, then the compliance boundary.

Q. And let me just stop right there for one second. Now, this letter is directed to Brenda Brickhouse at Progess?

A. Uh-huh.

Q. So could that -- do you think -- does that tell you whether this was directed to a landfill or not?

A. No, it doesn't tell me.

Q. Okay. So it could still be directed to a landfill because Progress had landfills?

A. I believe they had landfills; I don't know for certain. I don't recall.

Q. All right.

A. But I mean, it was trying to again map the site, map the waste sources on site, map where the well locations are in relation to all those in addition in where the review boundary and the compliance boundary were because those are necessary to make a determination as to whether there are any groundwater exceedances.

Q. Okay. And so that would be sort of then below that the determination of exceedances?

A. Yes.

Q. Okay. What about that third part, planned action as a result of the exceedances? What does that mean?

A. Just what actions was the company going to take if they found there were exceedances of the groundwater standards.

Q. What are possible actions that a company would take if they found there were exceedances?

A. I don't know. That is not my area of expertise.

Q. Okay.

A. They would be responsible for doing something to address a plume of contaminants exceeding the standards.

Q. Who -- what -- how would you describe that area? I mean, is that the area of corrective action? Is that what we're talking about or --

A. I don't believe that we got to corrective action plans. That is one possible outcome, but I don't recall that we had gotten to any specific corrective action plans because we didn't have sufficient information to direct that kind of activity, as I recall.

Q. Okay. But specifically, was there someone within DENR who had that area?

A. Well, corrective actions there were --

Q. And I'm sorry, that's a confusing question. We had first talked about just, you know, planned actions as a result of exceedances?

A. Uh-huh.

Q. So and you said that's not something you would get involved with, but was there a place in DENR that would get involved?

A. There were staff, and let me rephrase what I said. There were staff who had expertise in this area. It was not my area of expertise, so I relied heavily on the staff who oversaw this part of the program.

Corrective action plans were things that were required for groundwater contamination, both out of the Division of Waste Management and the Division of Water Quality, so there are issues about sources of plumes and how corrective action plans might be required under which authority to address a site as complicated as a utility site.

Q. Okay. So there was people who dealt with this within the Division of Water Quality, but it just wasn't you in particular; is that what you're saying?

A. Yes, that's correct. Staff in the aquifer protection section dealt with this. Staff in the Division of Waste Management also dealt with this issue.

Q. Okay. And let me just go back to one question I asked earlier, Miss Sullins, which is whether this could apply to landfills. I want to see some clarification there. I mean, if you look at the top of the letter it talks about this voluntary monitoring to help determine the environmental impact of coal ash storage in on site ash ponds.

Does that suggest that this was really focused on the ash ponds as opposed to landfills?

MR. ANDERSON: Objection.

A. The letter certainly is written to determine the environmental impact of coal ash storage on ash ponds. The problem with these sites is there was not just a coal ash pond on these sites. There were other activities that would also impact the determination of whether the coal ash pond was the source of the contamination.

Q. And do you know specifically which sites that is true of?

A. I do not.

Q. You just remember that as an issue?

A. Absolutely.

Q. All right. Do you -- you may have -- strike that.

All right. Let me show you another document. I guess we're going to need another sticker for this one. You can take the original there. Called -- we'll call this 199.

[EXHIBIT 199 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. Why don't you take a look at that one. This one is somewhat lengthy so --

Have you had a chance to look at that?

A. I have.

Q. So can you tell us what this document -- this first document looks like there's maybe three documents or four documents together here, but this first document represents?

A. It looks like it is a draft directive, if you will, from the director's office to the aquifer protection and surface water sections.

Q. Okay. Do you remember being involved in this draft?

A. I do not.

Q. Do you think -- can you tell from looking at this whether you were involved in writing it?

A. It is improbable that I was involved in writing it.

Q. Why do you say that?

A. The edits are not in my handwriting.

Q. And when you say edits, are you talking about the ones where -- what edits are you referring to?

A. There's an edit that says APA will -- "APS will enforce or recommend to NPDES enforce??"

Q. Uh-huh.

A. There are edits on the next page as well.

Q. Uh-huh. Now, could those be notes or do those look like edits to you?

A. The first one looks like a question that's being asked as part of the editorial process. The others look like they are actual edits of that first document.

Q. So let's see, if you don't -- you don't remember specifically being involved in this directive; is that right?

A. That is correct.

Q. Do you remember issuing any directives in connection with the coal ash groundwater monitoring?

A. I don't.

Q. Let's see if we can -- let's talk about some of the things that are mentioned in this letter aside from the memo itself. So do you see where it refers to in the second paragraph "APS sent a letter to both Progress Energy and Duke Energy requesting more information so that a determination could be made whether the data exceeds the regulatory standards?"

A. Yes.

Q. Do you think that's a reference to the letter we just looked at?

A. It could be. I don't remember the date of the letter.

Q. I'll show you -- I guess this was Exhibit 198.

A. It certainly could be a reference to this letter.

Q. Okay. And then it looks like there are two headings under that, right? One is compliance and one is enforcement?

A. Yes.

Q. Okay. And so what is the topic of the compliance? Just generally, what is the topic of the compliance section of this memo?

A. Generally, the topic is what we have been discussing is to determine whether there are exceedances in the wells that have been installed and where the wells are actually located.

Q. Okay. And so this is -- is it accurate to say this is sort of a next step in the process?

A. Next step from what?

Q. Evaluating the groundwater data.

MR. ANDERSON: Objection.

A. I don't know that I would qualify it like that because it actually talks about how they're going to evaluate the data. This memo talks about how the data is going to be evaluated and then it talks about enforcement.

Q. Okay. Doesn't it talk about how to get better data, right? Like doesn't the compliance section discuss, you know, whether you have to require the utilities to put in different wells?

A. Yes, it does talk about that.

Q. So well location is a topic here; is that fair to say?

A. Yes, well location is a key issue and a topic.

Q. And I had one question about that. If you look at the compliance one -- first of all, do you know whether this memo actually went out or not; do you have any idea?

A. I don't recall.

Q. Okay. If you look under compliance 1. I guess it's (b)2 it talks about "if you have a situation where the well is at or beyond the review boundary but inside the compliance boundary require the permittee to take actions in accordance with the statute or regulation or if approved by the APS regional supervisor, construct a well at the compliance boundary;" do you see that?

A. I do.

Q. Do you -- can you comment on why approval would be required there for a step like putting a well at a compliance boundary?

A. Without looking at that particular regulation I'm not sure what distinction they're making. I don't recall those details.

Q. That's fair. So one of the topics under this compliance section is well location which we've talked about?

A. Yes.

Q. And then if you look at the enforcement section, what's sort of being discussed there? What's the topic there?

A. Just how the enforcement action will go forward and internal to the division.

Q. That's sort of a jurisdictional issue within the division, if you will?

A. Yes.

Q. Was there any discussion in this draft about notices of violation?

A. It just talks about the lead for enforcement, if enforcement is necessary.

Q. And where are you looking?

A. On page 2 it says "if enforcement actions are required due to permit non compliance, NPDES will be the lead in enforcement actions as they're doing or do require to non compliance under the groundwater standards." That's what the 2L is, that the aquifer protection section will take the lead.

Q. So this doesn't get into, you know, any specific issues involving notices of violation?

A. It does not.

Q. Let's look at the second memo. We'll mark this 200.

[EXHIBIT 200 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. This one is a little bit longer.

Have you had a chance to look at it?

A. I have.

Q. Do you recognize this document?

A. I do not.

Q. Okay. It's another draft memo written to be from you; is that right?

A. That is correct.

Q. Okay. Do you -- do you ever -- can you explain how memos like this would come to be if you never saw them? I mean, do you think or what -- do you think you saw this at some point?

A. I don't recall. It doesn't have my signature on it so I don't specifically recall seeing this document. Documents like this would come about if there was an issue that crossed sections and the sections felt like they needed to have something specifically from the director's office to coordinate -- to enable them to coordinate with each other more effectively, then the sections would draft a memo such as this.

Q. Okay.

A. This memo would not -- would not reach me until it had gone through the sections and the deputy director before it would get to me for my signature. I just don't recall. I don't recall seeing this document.

Q. When you say your signature, do you put your initials by your name to finalize it; is that what you mean?

A. Yeah, I would either sign it outright or initial it, yes.

Q. And one of the issues, I mean, again are the issues discussed here sort of similar to the ones we saw in the previous memo?

A. Yes, they are.

Q. Do you see any differences at all?

A. The issue of overlapping compliance boundaries with facilities outside of the Division of Water Quality's responsibilities is addressed in here and I believe that's the first time that's specifically addressed in the memos you've shown me.

Q. And what -- can you explain that issue?

A. That goes back to the question of the -- whether the exceedances would be caused by a facility that's permitted by another agency. For example, the ash landfills versus the ash ponds, the Division of Waste Management was responsible for the ash landfills.

Q. And again that's sort of a jurisdiction question?

A. It is a jurisdiction question.

Q. Do you know whether in either -- you refer to these as directives. Is that sort of the word you would use?

A. That is the word I would use, yes.

Q. Would the utilities have any role in the drafting of these directives?

A. In the drafting of the directives, no, but we would certainly have meetings with the utilities and talk about where we were headed and why and discuss and disagree sometimes and agree other times about what direction we would be headed.

Q. Would it surprise you to learn if they had suggested edits to these documents?

A. I don't know that it would surprise me so much. I'm certain the utilities would certainly have interest in what might be included in these documents.

Q. Would utilities receive drafts of things like this before they were finalized?

A. They might have, yes.

Q. And what would the purpose of that be?

A. Just to the direction the division was headed and what concerns they might have that we might be unaware of in terms of how their facilities are set up.

Q. Is that something that would be -- you would be aware of before signing something?

A. I would be aware that there had been meetings with the utilities to discuss the issues. I would be aware if there were areas of disagreement just so we could be prepared for how we were going to manage those areas of disagreement.

Q. But what if there were particular edits that had been made to a document like this by utilities outside of DENR?

A. I don't know specifically. I'm not sure I specifically understand how edits would be made by the utilities outside of DENR. I can see how the utilities would make recommendations to staff on what they thought edits should be and provide that to the staff; whether the staff agreed with them or not would be the issue that would come to me, I suppose.

Q. Okay. And I'm not -- I guess I don't -- that's not a distinction that I'm asking about. I guess I'm asking, though, if that had happened, if a utility had edited an internal document and had --

and whatever the staff who was working on the document had accepted thos edits, is that something that you would know about or no? Would someone tell you that or was that common?

A. I don't know that the staff would have specifically said the utility edited and made these changes, recommended changes to the document. I would know that the staff had met with the utilities to discuss the actions that the staff was proposing that I sign off as a directive that would affect them and their facilities.

Q. And again this -- does this memo talk about enforcement issues?

A. Yes, it does.

Q. And where are you looking?

A. I'm looking at the compliance of surface water standards, the section that talks about that, it talks about enforcement. The compliance of the groundwater standards, it talks about corrective action in accordance with the rules and that again is -- can fall inside an enforcement arena.

Q. And where do you see the reference to corrective action?

A. Under 3(c).

Q. Oh, okay. And what does that -- can you just read that, what does that say?

A. It's talking about review of groundwater monitoring data and what will happen if there are exceedances and paragraph C specifically says if the well is at or beyond the compliance boundary, APS will require permitee to take corrective action in accordance with 15(a) NCAC 2L.0106(d). If the permitee meets all requirements under 2L.01 1016(e) or 15(a) NCAC 2L.0106(c) if the permittee does not meet all the requirements under 2L .0116(e).

Q. This was written by somebody who spends a lot of time with that statute, I imagine?

A. Yes, it is.

Q. To your -- Miss Sullins, to your knowledge, was that ever done? Was the permittee and I guess in this case we're not -- they just talk about utilities, they don't specifically talk specific permittees, but was a permittee required to take corrective action?

A. I don't recall that this issue was sorted out by the time I left the division.

Q. Okay. And there's not a reference here to notice of violation unless I missed one. Did you see one?

A. It just -- under the compliance of the surface water standards, paragraph B says the NPDES compliance and enforcement branch will take any followup -- it says under the compliance of the surface water standards paragraph B, "the NPDES compliance or enforcement branch take any followup enforcement actions as deemed necessary."

Q. We've got one more document from 2009 and then maybe we'll take a break, if that makes sense.

A. That's fine.

Q. It's a pretty short one. So this is 201.

[EXHIBIT 201 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. And Miss Sullins, I'll just tell you I'm not going to ask specific questions about the attachments which are several pages, so if you want to focus on the letter itself, that's what I'll be asking you about.

Q. Okay. So this is a letter that you were cc'd on; is that right?

A. That is correct.

Q. Do you remember this letter going to Progress?

A. I do not.

Q. What are -- can you just summarize the -- what is the purpose of this letter?

A. Clarification of how the regulations apply to the facilities that were permitted prior to the December 30th, 1983 and establishing the groundwater monitoring wells were needed at the compliance boundary, and providing direction to do that to install wells or I didn't look at the specifics.

Each site has specfics associated with it to obtain the information upon which determinations could be made.

Q. Okay. So let's break that down just a little bit. So there's a request that each facility put groundwater monitoring wells at the compliance boundary; is that right?

A. That is correct.

Q. Is that a voluntary request? I mean, could the utilities ignore that if they chose to?

A. It is not stated as an absolute.

Q. But then two sentences later it says "as permits are renewed, groundwater monitoring will be added to the updated permits and similar parameters will be required to be monitored at each site."

A. Which would make it a regulatory

requirement.

Q. Is that the issue that you talked about first coming up back in the '90s?

A. Yes.

Q. Okay. Is this the first time that this is being -- that the utilities were being told this?

A. I don't know.

Q. That's a significant issue, isn't it?

A. It certainly is a significant issue.

Q. Do you understand what the letter is saying with respect to the relationship between this, I guess, legal determination and putting monitoring wells at the compliance boundary? Does that -- I'm asking because I don't quite understand it, but --

A. I do not recall the details of the 2L requirements and the application of them to these particular facilities. It appears to me from this letter that there was a determination that the regulations -- a determination needed to be made about permitting facilities that were in place prior to regulations going into place that specifically addressed those issues, groundwater. And that that's what the clarification from the AG's office was about.

Q. And it says "this clarification gives

Progress Energy the option to seek approval of a corrective action plan that does not require remediation to groundwater standards or may allow attenuation by natural processes;" do you see that?

A. I do.

Q. And so are those -- would you consider those to be advantages in a corrective action plan?

MR. ANDERSON: Objection.

A. Well, for the facility certainly to be able to allow a plume of a contaminant to attenuate rather than to have to install treatment, that would be, I would assume to be an advantage to the company.

Q. And what about not requiring remediation?

A. That's what I was just trying to describe, I'm sorry. So if a plume -- natural attenuation in essence allows the plume to continue to dilute within the groundwater and you do not have to actually treat through a remediation.

Q. Can you -- I mean, the reason I ask that is it looks like it talks about these as two separate things. It says "does not require remediation to groundwater standards or may allow attenuation by natural processes."

So can you distinguish those two? I mean, is there a situation in which -- are they really kind of one and the same?

MR. ANDERSON: Objection.

A. I believe them to be one and the same thing. I'm not sure why "or" is in there.

Q. All right. Is now a good time for a break? Can you do that?

A. Sure, that's fine.

MR. WHEELER: Okay, let's take a break.

THE VIDEOGRAPHER: We're off the record at 10:40 a.m.

[RECESS - 10:40 A.M. TO 10:54 A.M.]

THE VIDEOGRAPHER: We're back on the record at 10:54 a.m.

BY MR. WHEELER:

Q. Okay. Miss Sullins, we've been talking about some internal memos and questions about utilities and we're moving into 2010 now. Trying to do this chronologically, okay? And what I wanted to ask you was what level of attention was the coal ash issue receiving in the public at this time? What do you remember about that?

A. I don't recall the degree of attention that was -- it was receiving in the public.

Q. Was there any -- was this an issue where there were press reports or --

A. Again, I don't recall the specifics on a timing basis. There was a lot of interest in the coal ash issues, but I don't remember the specifics of press engagement, et cetera.

Q. When you say interest, what are you recalling?

A. There was interest in the department. There was interest by the Commission. There was interest by EPA. There were a lot of different issues swirling around coal ash. I just don't remember the press aspect of things.

Q. What about from the public environmental groups, things like that?

A. Again, I don't remember the specifics of it. Environmental groups have tended to be interested in any significant issues that the Division of Water Quality was dealing with.

Q. All right. Let me show you a document. We're going to mark this 202.

[EXHIBIT 202 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. And let me just describe this document so you understand what you're looking at from how it's put together. This is an email on which you appear to be copied and then there's an attachment.

The attachment was quite long so rather than putting the entire attachment on, it's an excerpt from the attachment. I just want to make sure you understand that. And I just excerpted the parts of the attachment that directly refer to the Sutton plant.

Miss Sullins, have you had a chance to look at that?

A. I have.

Q. Do you remember seeing this report called Out of Control, Mounting Damages from Coal Ash Waste Sites?

A. I have a vague recollection of this, but not specific.

Q. And was this a common occurrence where something like this would get circulated at DENR?

A. I don't really know how to answer that question. If issues came up that were related to any permitted entity where there was some kind of a report that an external group had done, it would certainly get circulated internal to the department with request for response to what was happening from our perspective.

Q. So it was common?

A. Again, I don't know that I would call it common, but it -- if external reports occurred like this, they would certainly get circulated for input. Again, they're not a lot of external reports like this, but the actions that were taken, you know, circulating it around the department are consistent with what actions would be taken.

Q. All right. So I'll ask a better question. Was it -- was one these reports unusual? In the course of a year would you see these reports, you know, how -- what would you say about that?

A. I would say that there was a lot of interest in the water quality programs by external parties. I have no idea of the frequency of these kinds of reports that we'd get. We would get a lot of public press on different issues and requests for comments from the staff associated with those. This -- this -- this type of report again, I don't know that I saw a lot of these, but they did come through.

Q. And I hadn't asked you this before, Miss Sullins, but were you specifically familiar with the Sutton power plant?

A. Can you explain what you mean by

specifically familiar?

Q. I mean did that have -- if someone said Sutton Lake to you, did that have meaning to you or --

A. I knew the power facilities. I don't believe that I ever visited the Sutton steam station, but I certainly knew of it and the other facilities in the state.

Q. So let's look at the excerpt. Do you see where there's sort of this narrative description in this table where they're talking about Sutton?

A. Yes.

Q. And is there a statement there about monitoring and where the contamination has been found?

A. The statement says that monitoring indicates "the contamination is migrating outside of the state designated compliance boundary on site."

Q. Okay. And then below that does it say something about the state action?

A. Notice of violation, request for corrective action.

Q. Do you know whether anyone at DENR was asked to kick the tires on this report to see whether, what DENR's position was on it? I think you just described that was something that might happen.

A. Certainly. I mean we would ask staff for feedback associated with reports like this coming out that it pertained to the programs that we were responsible for.

Q. All right. Let me show you, this is something that was previously marked as Exhibit 25. And if you see, this appears to be an email from someone named Charles Stehman?

A. Yes.

Q. Do you know who Mr. Stehman is?

A. He was the regional supervisor for aquifer protection in the Wilmington regional office.

Q. And is he still employed -- you said he was. So is he no longer employed at DENR?

A. I believe Charlie retired.

Q. Was he someone who you had -- can you just describe, generally, your working relationship with him? Is he someone you had frequent contact with?

A. I met the supervisors for the division. I believe there were 60 of them, every other month, much to their objection. Called them in for a staff meeting on a regular basis so I would see Charlie at least every other month.

I certainly, you know, worked with him and worked on issues with him when I was over the programs that involved his part of the program, so since April of 2003 or '4.

Q. And then who is Debra Watts?

A. Debra Watts was one of our groundwater supervisors, I believe, our aquifer protection supervisors. I don't remember her specific role. She was in the central office. She might have been over the permitting programs. I don't recall her specific role.

Q. And does this appear to be what we were just describing, someone asked to comment on a report that came out?

A. It specifically says "here are my observations and comments concerning the coal ash report."

Q. Okay. And in the subject line it talks about this Out of Control title, I guess?

A. Yes.

Q. All right. Looking in the summary table do you understand these to be Mr. Stehman's comments about the report? Sort of like he's fact checking the report; is that --

A. Yes.

Q. Now, at the bottom of that summary table section where he's making comments, did he find something that was not accurate about the report in terms of notices of violation?

A. Well, he specifically says the Wilmington office of the Division of Water Quality has not issued any notices of violation related to arsenic or boron in groundwater beneath the Sutton property.

On September 8th, 1987, a notice of non compliance was sent to Carolina Power & Light now Progess Energy concerning chloride and total dissolve solids, contamination in groundwater to the east of lake Sutton which contains the Sutton ash ponds.

Q. Is the regional office the best place to understand that kind of information?

A. The regional office is the staff that is most familiar on the ground with the specific facilities.

Q. And then going back up, Miss Sullins, what does he say about boron?

A. He said arsenic, boron, iron, manganese, and boron. I'm sorry, I think you're looking for the sentence that says "boron has been detected at locations outside of the compliance boundary at levels in excess of the state groundwater standards."

Q. Okay. And so does that suggest that there were a well or wells at or outside of the compliance boundary?

A. I'm not sure exactly what it suggests because of the determination under the narrative seems to say something different: "No evidence to date that arsenic or boron have migrated beyond Progess Energy property."

Q. Where are you looking?

A. I'm looking under narrative beginning on page 37, Determination.

Q. I'm not sure I get that. Why are those inconsistent?

A. Well, it says no evidence to date that arsenic or boron have migrated beyond Progess Energy property. And then up above it says "boron has been detected at locations outside the compliance boundary at levels in excess of the State's groundwater standards."

I don't know other than it may be a question of migration and a determination has not been made of migration from the Progress Energy site. I don't know.

Q. Well, wait, wouldn't -- couldn't the compliance boundary be within Progess property? The compliance boundary is just a fixed distance from the waste site, isn't it?

MR. ANDERSON: Objection.

A. I don't recall the definition of compliance boundaries. What I do recall is that the definition gets very complicated and that there are different sites for which the compliance boundary is differently located than other sites.

Q. Okay. But again, Mr. Stehman would be the person who would be following this the most closely you think?

A. I would expect, yes.

Q. Okay. And so if he says there's boron detected at locations outside of the compliance boundary at levels in excess of State groundwater standards, do you have any reason to think that's not accurate?

A. No, I have no reason to believe that's not accurate. I don't know how it's consistent with the statement below that says "Determination, no evidence to date that arsenic or boron have migrated beyond Progess Energy's property."

Q. Well, couldn't it be consistent if the compliance boundary was on Progress property?

A. It could be, yes.

Q. Okay. So do you know in connection with this detection of boron at locations outside of the compliance boundary whether a notice of violation was issued by Mr. Stehman?

A. I don't know.

Q. Could a notice of violation have been issued?

A. It's possible.

Q. I mean could that, that would have been permitted? I don't mean could it have happened.

A. I'm not sure there's sufficient information here for me to make that decision.

Q. Why do you say that?

A. Because there is very limited information here and I don't know -- I don't know the specifics of what's been going on at the site.

Q. But if a 2L standard has been exceeded outside of the compliance boundary, isn't that a problem?

MR. ANDERSON: Objection.

A. I would say if boron has been exceeded outside of the compliance boundary that there is merit to evaluating whether a notice of violation should be issued.

Q. What does that mean "merit to evaluating?"

A. To evaluating the situation on the ground. We did not issue notices of violation for every violation that occurred within the State; it's just not possible.

Q. So DENR has discretion as to when to issue a notice of violation?

A. Yes.

Q. I guess what I'm asking is based on this exceedance, was a notice of violation a potential action by DENR?

MR. ANDERSON: Objection.

A. Based on this limited information that I have here in front of me DENR would have had the discretion to make a determination as to whether to issue a notice of violation for boron.

Q. Okay. But you don't know whether that in fact happened or not?

A. I have no idea.

Q. Do you remember the impact that this -- did this report affect DENR in any way? I know we talked earlier about how the Tennessee Valley issue prompted some questions to the utilities, right? We talked about that earlier?

A. It prompted questions. It prompted inspections. It prompted reporting to multiple arenas on the larger scale of issues at the facility, yes.

Q. Did something like this have that same kind of impact or --

A. I don't recall.

Q. Do you remember an issue coming up really, I really -- I guess I'll describe it as a legal issue involving whether Lake Sutton should be considered waters of the State?

A. I vaguely recall this.

Q. Okay. What do you recall about it?

A. Just that there were questions as to whether Lake Sutton itself should be considered waters of the State or not.

Q. Was that something that was -- what do you remember about who raised that issue or how that issue came up?

A. I don't recall how that issue came up, honestly.

Q. Do you remember if it was an abstract thought or something was actually going on with Lake Sutton?

A. I don't recall.

Q. I have an email I can show you. Give me one moment here. This is 203.

[EXHIBIT 203 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. This is a string of emails and so I believe it goes from back to front in terms of order, Miss Sullins, so that makes it a little trickier.

Miss Sullins, do you recognize the individuals who were involved in the correspondence back and forth?

A. Absolutely. Rick Shiver was the surface water supervisor, Linda Willis was one of his staff, Kathy Cooper was with the AG's office. I think -- I know Rick is retired. I think Kathy is retired and I don't know if Linda is still with the Division or not.

Q. And what was the AG's office -- what was the role of the AG's office in connection with matters that would come up? Were they considered your counsel?

A. We would go to them for legal advice. They would act as our counsel when issues were litigated.

Q. And in this case, did Miss Cooper provide an answer to a question based on her review of the statute about whether this cooling pond was waters of the State?

A. She qualified her answer based on the need for further discussion internal to the Division.

Q. Well, let me -- first let me just focus on my question which is did she provide an answer about what the statute and rules say?

A. What she said is based on my review of the statute and rules, I think a cooling pond as you described Sutton Lake is waters of the State. However, if other sections within DWQ don't consider it to be waters, we need to know why before I give you a definitive opinion since there may be a policy reason why DWQ has not historically considered cooling ponds waters of the State.

Q. Does that help you recall this issue at all? Do you have any memory of this issue coming up?

A. Not specifically, no.

Q. I'm trying to understand why -- what DENR's role is in making this sort of -- in doing this analysis. Is this a situation that could come up where the AG's office would express an opinion about a statute, but then DENR would have to weigh in on the issue?

A. The typical working relationship, if I can describe it that way, between the AG's office and the Division of Water Quality, let me be specific about this, is the Division of Water Quality is it was a collaborative process to come to a determination when we had issues that we felt we needed to request their assistance on.

Q. And how would the collaboration work?

A. We would sit down and have discussions about what the statute said and arrive at what we felt like was the best answer given the issues and the statute and regulations before us.

Q. Well, did that kind of collaboration happen here?

A. It appears that there was an initial discussion between the regional office and the AG's. Did not include all of the staff of the division.

Q. Okay. Do you see these notes that are written next to that email?

A. I do.

Q. And I'm just reading the last few sentences where it says "per Chuck," how do you pronounce Chuck's last name?

A. Wakild.

Q. "Wakild and Coleen Sullins, DWQ wants to be free to make their own decisions." Do you recall a conversation where that was expressed, that -- sort of that approach?

A. I recall conversations where we would make decisions as to whether we needed to have the AG's office input or not. The AG's office tended to be more cautious than the division staff and I would -- I preferred as director and as supervisor over the years to have that opportunity to make those decisions about how we were going to act on a situation and then consult with the AG's office if we felt like it was something that we needed to have further consultation.

Q. So this was a situation where someone had gone to the AG's office very early in the process; is that fair to say?

A. That is fair to say.

Q. And is that what you -- do you recall that's what you were reacting to?

A. That is what I was reacting to.

Q. Is this something that happened frequently?

A. It happened occasionally.

Q. Okay. Did the AG's office ever express displeasure that they had given you some advice and then, you know, it had been too early in the process and you determined that you didn't even want the advice?

A. I don't recall that we ever had that discussion.

Q. Do you remember anything else about this issue? Was this the end of it? Was it resolved and --

A. I really don't remember.

Q. All right. So we're into 2011 at this point, Miss Sullins, and there is -- do you remember an effort to come up with ash pond compliance and enforcement guidelines?

A. I don't specifically recall that. That would not surprise me that the staff had been working on that.

Q. Okay. Let me -- I'm showing you an email that may help. I think we're on -- does 204 sound right? Okay.

[EXHIBIT 204 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. So I'll give you a second. And Miss Sullins, I'll say similarly you're free to read the attachments. I'm only going to be asking you about the text of this first email, Exhibit 204.

So Miss Sullins, does this help refresh your memory on sort of the efforts that were going on in 2011 on this issue?

A. Again, it's one of many efforts that were going on associated with the ash ponds. This is something that the staff were working on.

Q. Okay. Do you remember it?

A. I don't remember the specifics of this, no.

Q. Okay. And if you look down at the -- let's look at the fourth paragraph. It's not clear from the email who is writing this. I believe though if you look at the back of the email it's Debra Watts' name. Do you see where she says "at our next meeting with Progress and Duke I've asked Evan to discuss all the 2L options available to the permittee (variances, groundwater reclassifications, natural attenuation, et cetera) once they are determined to have groundwater exceedances?"

A. Yes.

Q. Do you remember any concerns being expressed by Duke and Progress about these groundwater issues?

A. I was not involved in all the meetings with Duke and Progress. But generally speaking, they would raise concerns about any regulatory issue that we were taking up and might be moving in a different direction than we had moved in the past.

Q. And elaborate on that a little bit. What different direction are we talking about here?

A. Well, we're talking about compliance actions specifically associated with the ash pond, ash pond compliance and enforcement. So we're talking about moving in some new directions as to how they're going to be applied to those facilities.

Q. Okay. And who is Evan?

A. Evan was one of the supervisors. I believe he was a supervisor at the time over the aquifer planning.

Q. Do you remember any specific conversations either -- well, let me ask you first this question. Did you interact with representatives of Duke or Progress on groundwater issues that you recall?

A. I don't recall the specifics of meetings. I certainly met with Duke and Progress over the years. I just don't recall the specifics.

Q. Do you remember the discussion of groundwater issues at any of those meetings?

A. Again, we were meeting with them associated with the issues that we were finding at the facilities following our initial undertakings of inspections, et cetera, starting in 2008, I believe it was.

So I am sure I discussed groundwater issues. I was part of the discussion. I don't recall the meetings.

Q. Okay. What does this mean where it says the 2L options available to the permittee and then it names four, and et cetera, once they're determined to have groundwater exceedances? What does that mean?

A. That means those options are open to the permittees. They can request a variance from the standard. They can request that the groundwater be reclassified. They can request that natural attenuation. I think that attention is the wrong word there. Natural attenuation, whatever the options are that are available under 2L to specifically address groundwater exceedances, they have options on what they can request.

Q. And so for example, how would a variance work?

A. A variance from a standard is a rule making process so a request for a variance would have to come in along with the documentation as to why the variance was needed and that request would go before the Environmental Management Commission for a decision to be made.

Q. Do you recall Duke or Progress ever asking for a variance on the 2L standards?

A. I do not.

Q. What about groundwater reclassification?

A. I don't recall that we got into those conversations.

Q. This is a document that's previously marked as Exhibit 50.

Miss Sullins, this is the kind of thing that -- would you characterize this as a, you know, nuts and bolts kind of back and forth between a regional office and a regulated entity?

A. I think that's a good classification.

Q. And what is the subject matter of this communication?

A. The subject matter is that "Phase I groundwater quality assessment for the ash ponds."

Q. And who put that together?

A. Progress would have put that together.

Q. And is Mr. Stehman, does he reiterate the conclusion about boron here?

A. He makes the statement about non compliance, "boron has reached the compliance boundary and total dissolved solids have crossed the compliance boundary."

Q. Okay. Do you know what happened in connection with those -- do you know if anything happened in connection with those conclusions other than what's in the letter?

A. I don't know.

Q. All right. Is this the kind of decision -- I know again we're March of 2011 coal ash issue, one of the plants. I understand this communication is not something you would have seen; is that correct?

A. That is correct.

Q. Is this the kind of issue -- if someone was thinking about whether there should be a notice of violation, is that the kind of thing that you would have been involved in?

A. Not necessarily.

Q. Okay. And just explain that, based on what you see here.

A. Well, based on what I read here it doesn't appear to me that the regional office is considering issuing a notice of violation.

Q. That's not really my question. My question is if the regional office was considering a notice of violation, is this the kind of thing that would have happened at that level or would have gotten someone involved in Raleigh or you, you know, that sort of thing?

MR. ANDERSON: Objection.

A. The regions send out notices of violation frequently without any consultation with the director's office. As a matter of fact, it would be -- it's more the reverse that the director's office gets engaged in a notice of violation. It's typically handled at the staff level and not at the director's level.

Q. Let me make sure I understand that. We talked earlier about how different violations get handled differently in terms of where, right? So we talked about how the permit, you know, you forgot to file your permit or your report, excuse me, that's clearly a -- you say staff level. Does staff level mean regional office to you?

A. Staff level can be regional office; it can be central office.

Q. Okay, all right. So staff level issues are the issue, I mean, it's sort of things get escalated, right?

A. Things get escalated, correct.

Q. And so I'm just trying to figure out for something like this, non compliant boron in the coal ash, is this -- would this have been escalated if someone was thinking about a notice of violation?

MR. ANDERSON: Objection.

BY MR. WHEELER:

Q. If it's just too hard to speculate, you can tell me that.

A. I was going to say that's really too difficult for me to speculate on.

Q. Okay.

A. We were reporting regularly on the status of coal ash and actions taken on coal ash we were reporting to the Commission and the Department on a regular basis. That's -- you know, so in terms of, you know, whether a notice of violation would be issued, I really can't speculate on that based on this, but based of the reading of this, it doesn't appear that the region has any intention of or would recommend a notice of violation.

It appears to me that they're concurring with the report recommendation that permanent monitoring wells be developed to evaluate the contaminant plume migration and attenuation.

Q. Right. I understand that's what the letter says and I was just trying to understand the scope of this kind of decision. You know, we've talked about scope before, right, minor forgot to turn the permits in on time?

A. Right.

Q. To major, and so I'm just trying to get a sense for that, if you have any thoughts on that.

A. I mean, I really -- I don't really have any thoughts on that. I don't feel like I have enough information to speclate on that.

Q. Okay, that's fair. All right. Let's look at -- let's see. It's already been marked, sorry. This is marked as Exhibit 47.

Okay. Do you remember, Miss Sullins, I think we previously asked about this when we talked on the phone. Do you remember us mentioning this memo?

A. I can't say that I specifically remember this memo, no.

Q. Do you -- well, do you remember us asking you about it?

A. Honestly, I left town the next day and was -- and that's what was on my mind was getting out of town.

Q. Sure, I understand. Looking at it today, do you recognize this memo?

A. I don't remember this memo.

Q. Okay. What is the subject of the memo?

A. It's a policy memo for evaluating long-term permanent facilities with no prior groundwater monitoring.

Q. Did this come out of the efforts that we were talking about a few moments ago where the staff was thinking about coal ash compliance issues, do you think?

A. I don't know. I could certainly speculate that that was part it. I don't think it was the sole reason for this, but I don't know.

Q. What are the purposes of these? Is this a standard kind of document, a policy document?

A. Policy documents get developed when it's unclear how certain actions should be taken. And since you have a variety of staff who might be taking those actions and you might have inconsistencies in the way they would be applying their interpretation of the regulations, that usually results in a policy document to provide clarification, to assure consistency and implementation across the State.

Q. When we talk about the Division of Water Quality, I don't know, at the time that you left, how many policy documents would there be?

A. I have no idea, a lot.
Q. All right. Are they stored in some place where everyone can get to them?
A. What a good idea, no. I -- they would be managed by the section for which the implementing program area would have and I would assume that the surface water section would also -- surface water protection section would also have this document --
Q. Okay.
A. -- available for staff making decisions that might relate to this.
Q. And when you say the section, here you're talking about the aquifer protection section?
A. The aquifer protection section would be the lead for managing this kind of a document, but the surface water protection section would also have need of this document for purposes of permits that they were issuing.
Q. What sort of approval process does something like this go through?
A. It depends on the policy and the issues. Sometimes policies would come up to the director's office, sometimes they wouldn't.
Q. Did you have any policy on when one of those things should happen?

A. No.
Q. Do you know whether this came to the director's office or not?
A. I don't.
Q. How would you -- how would someone determine whether it did or not?
A. I would assume that the director's office would have been copied on it.
Q. And so by definition if you're not copied on it then does that suggest it wasn't circulated to you?
MR. ANDERSON: Objection.
A. It would suggest that it was not circulated.
Q. Do you know whether -- were regulated entities involved in the creation of these policy documents?
A. Regulated entities were certainly involved in policy documents frequently.
Q. Okay. And explain that a little bit; how would they be involved?
A. Well, if they had an interest in the specific issue and we were meeting with them on it, then we would be discussing the issues with them. Yeah, I can think of a variety of situations where

regulated entities, whether it be the utility companies or the animal waste industry, would get very involved in decisions that we were making and wanting to have input into the decisions that we were making.

Q. Would the public get involved in these things?

A. The public could certainly be involved in these things.

Q. And how would that happen?

A. Well, with the -- thinking back on the animal waste situation, we had meetings that involved the public and the industry and had in-depth conversations with them.

The public would get involved in a policy situation sometimes when we issued permits and they disagreed with our interpretation and the decisions on making the issuance of the permit and then the policies would get debated at that point in time. So there were a variety of different avenues through which the public might get involved.

Q. Is -- would there be notices that were like in the animal waste, it sounds like you sort of remember that one in particular?

A. I do.

Q. Were notices given? So how do people know there's going to be the meeting?

A. It depends on the issue again. This was probably discussed at staff meeting and was not discussed in a public setting. It may have been and I do not know, it may have been discussed with permittees who had these kinds of facilities.

You know, I don't -- I don't know whether the public was involved with this one at all or not.

Q. Can you tell us, does this -- what is the relationship between this and those drafts we looked at from 2009? Is this -- I think you are probably the right person to ask this question. Does this seem like this is related to those, is it a continuation of those or do you have any thoughts on that?

MR. ANDERSON: Objection. Objection.

A. There's a relationship between them.

Q. Because isn't this talking about placement of wells?

A. It is, but it is also talking about permit conditions and how to put permit conditions in order to make compliance determinations. And the 2009 memos, as I recall, were more related to compliance.

Q. So let me see if I can process that. So one distinction is that this memo has to do with requirements going into a permit and the other memos had to do with steps to be taken just more generally with compliance; is that what you're saying?

MR. ANDERSON: Objection.

A. The way I read this memo it talks about the groundwater monitoring requirements are to be added to permits based on a series of factors. And those series of factors then will assist in making a future compliance determination.

So once those things get into a permit, then they will assist in the process of a compliance determination.

Q. Okay, let me just ask you about that. I see what you're saying here. The question I guess you're saying that right above these numbered bullet -- these paragraphs, type of permit activity subsurface geology, et cetera, it says "this is determined by considering at a minimum the following factors."

Are you -- is it your reading of this that this refers to whether or not to have groundwater monitoring requirements?

A. The statement says when groundwater monitoring requirements are added to permitted facilities that have operated for some time, it may be necessary to place wells at or near the compliance boundary rather than the review boundary.

Q. Let's stop there for a second. What does that mean?

A. So there's, and again, I don't remember the specifics of the regulations, but there is a review boundary and a compliance boundary and when you are permitting a new facility and you're putting wells as part of that permitting process, you put wells at the review boundary because you're trying to capture before a compliance boundary is violated. So that review boundary and a level that's above the standards is not a violation.

Q. Right.

A. At the compliance boundary it is.

Q. Right.

A. But when you have existing facilities that have operated for some time, and this relates back to the -- one of the previous memos that cited the AGs in the 1983 time frame, so when a facility has been in place for some time before the regulations have come into place, then you have to use some factors to determine where to place those wells.

Q. Okay.

A. And that's what I interpret this to be.

Q. Okay. That's how I interpret it too that these factors, tell me if you agree with this, these factors are what you're supposed to think about when you're trying to figure out where to put wells?

MR. ANDERSON: Objection.

A. That's correct.

Q. Okay. Not whether there should be any monitoring or not?

A. Well, the placement of the requirement to place a well results in monitoring because that's the purpose of a well.

Q. But aren't -- wait, those are two separate issues, aren't there, whether or not there's going to be monitoring and then where you're going to do it?

A. There are a series of monitoring so let me just discard the surface water monitoring because that's not the discussion we're having here.

If there is going to be a requirement for a well and a permit, along with that requirement is a monitoring program associated with the well. The Division wouldn't require the placement of a well unless the Division was going to require the collection of monitoring data from that well.

Q. Sure. Doesn't it go the other way? You first determine whether there's going to be groundwater monitoring, then you determine whether there are going to be wells because they might already have wells there, right?

A. They might already have wells on site, but the placement of the well as we've been discussing is important to determining compliance.

Q. Right.

A. And the wells may not be in a location that enables the Division to make a determination on compliance.

Q. Okay. But I think we're -- I just want to go back to make sure we're on the same page here, I understand what you're saying. It says "when groundwater monitoring requirements are added to a permitted facility that has been -- that has operated for some period of time," so that assumes that there's going to be monitoring requirements, right?

A. That is what it says.

Q. Okay. It may be necessary to place wells at or near the compliance boundary?

A. And that's a locational issue.

Q. Okay. And then this is determined by considering at a minimum the following factors. My question is that's referring to whether you have to put them at the compliance boundary, right?

MR. ANDERSON: Objection.

A. It's -- what I'm interpreting this to say it is the location of the wells is determined by -- for a facility that has operated for some time, the location of the wells needs to be determined by these factors.

Q. Yes, okay, that's what I thought you said. Just wanted to understand that, okay, thank you.

A. Uh-huh.

Q. But location of wells was something that was brought up in those previous drafts we looked at; is that fair to say?

A. That is fair to say.

Q. Okay.

A. And in correction of my previous statement it -- this does say if a facility is determined to be non compliant, there's a flow chart to follow that is attached as to the actions that are to be taken.

Q. All right. I'm sorry, what statement are you correcting?

A. I think I said I felt like this was more about permitting. There is a compliance flow chart that is attached to this document.

Q. All right. I see. And so let's talk about that. That's the -- this flow chart that's attached, what is the purpose of the flow chart?

A. Well, what the document says is if a facility is -- if a permitted facility is determined to be in non compliance after following the steps outlined in the flow chart, adherence to a corrective action requirement specified in 2L or 106 will be required.

Q. Okay.

A. And it goes on to say that if the permittee is cooperative in taking the steps necessary to bring the facility into compliance, a notice of violation may not be necessary.

Q. Okay. Does that refresh your memory on whether there were any specific concerns by Duke and Progess about groundwater monitoring?

A. My memory of this is not specific. My memory of this is that Duke and Progess were very concerned with the actions that we were proposing to take because they had a potential to significantly impact them.

Q. Okay. And what do you mean potential to significantly impact them?

A. If we started taking enforcement actions or altered permitting, those things would cause the company to have to spend resources to address them.

Q. Well, isn't it more than that in the sense that these were facilities that had been there for a while, right?

A. These are definitely facilities that have been there for a while.

Q. And there was already evidence -- there was already evidence that there was non compliance?

A. There is already evidence that there were groundwater exceedances, yes.

Q. Okay. Is that non compliant?

MR. ANDERSON: Objection.

A. Again it's specific. An exceedance isn't necessarily non compliance unless it's past the compliance boundary.

Q. Okay. Well, let me rephrase my question.

A. Thank you.

Q. There was already evidence that there were exceedances past the compliance boundary?

A. Certainly the memos have documented evidence of exceedances past the compliance boundary.

Q. Okay. And so once you turn on a monitoring requirement, wasn't the concern that you're going to have violations popping up?

A. If I were the company, that would certainly be my concern.

Q. Okay. And so this memo -- well, let's stay with the flow chart for a second. If you look at the flow chart, Miss Sullins, is this -- can you just tell me, is this sort of a -- what would you describe this as? I'm not familiar with these kinds of schematics. Is this an engineering kind of document?

A. I would say you see engineers use these kinds of documents.

Q. Okay.

A. I haven't looked at one in a long time. It's just a flow chart, decision flow chart, an effort to make a decision based on the information and to try and outline how different kinds of information might be pulled into play.

Q. Okay. So does it look like it starts over here in the upper left-hand corner?

A. It does.

Q. And it says use sampling or predictive modeling to determine groundwater quality and establish compliance boundary?

A. Yes.

Q. All right. And then it looks over and says okay, is the concentration greater than the 2L looks to me like what's that saying; do you see that?

A. Uh-huh.

Q. If yes, is it reported to the Division. What's the significance of that, if you know?

A. I'm not sure how the Division would have the information unless we did some monitoring ourselves. And I guess the other question is if somebody would have the information on site and when we did an inspection we discovered the information and it had not been reported.

Q. Does this seem to suggest that there is some obligation to report to the Division?

A. Oh, yes.

Q. By the permittee?

A. Yes.

Q. And then if it was reported to the Division, then you go over here and it says results greater than naturally occurring concentration and if it's no, then continue your monitoring, if it's yes, you verify the results.

One thing that I'm curious about, Miss Sullins, and I don't want you to speculate but only if you have an understanding of this is who is responsible for taking these different actions? Is this geared towards the utility?

A. This appears to be geared towards the Division staff.

Q. Why do you say that?

A. Because there's the question about if it was reported to the Division, number one. There is discussion about division regional office and the facility non compliant permittee coordinates with the Division and the regional office staff. Then there are some pathways. I mean, this appears to me to be direction to staff.

Q. And are you familiar with documents like this containing direction to staff? Do you remember any others?

A. I don't. I've seen these kinds of documents before. I don't recall specific -- specifics of what they were associated with.

Q. Okay.

A. So that was -- that's sort of the flow charts comes after these factors of well location that we just talked about. Is that how the memo kind of moves along?

A. Yes.

Q. All right. And then this last paragraph talks about as long as the permittee is cooperative with the Division in taking all necessary steps to bring the facility into compliance, a notice of violation may not be necessary. Is that -- are you familiar generally with that sort of -- a policy that contains that kind of language?

A. The determination of issuance of a notice of compliance -- notice of -- notice of violation is generally evaluated in the context of the history of a specific facility and impact that that violation may have in the environment. That -- that is not atypical of how the process works or worked.

Q. Well, this is a little different, isn't it? It says that -- it seems to give some benefit for cooperation.

A. Uh-huh.

Q. And I guess that's my first question is so is that, do other policies contain that sort of --

A. I don't recall specific policy statements, but I can tell you that historically that has been that was an issue that was taken into consideration associated with making decisions around compliance and the impact to the environment.

Q. And what is this language "all necessary steps to bring the facility into compliance?"

A. It's whatever actions are required for the facility to address the issue of non compliance.

Q. So that could include -- is that like a corrective action plan?

A. It could include a corrective action plan is one option.

Q. And is this written, Miss Sullins, in a way that takes away discretion from DENR about when to issue a notice of violation?

A. No.

Q. And why do you say that?

A. Because it says a notice of violation may not be necessary. It doesn't say a notice of violation is not necessary.

Q. And does -- what does the last sentence say there?

A. "The overall determination of whether or not an notice of violation is necessary will largely be based on the overall compliance history of the facility and the potential for the impacts to human health or the environment."

Q. And that's the human health issue you referred to earlier?

A. And environment, yes.

Q. Who is Matt Matthews; do you know who that is?

A. Matt Matthews was the section chief for the surface water protection section. He is retired.

Q. Do you recall talking about this memo with anyone?

A. I don't recall.

Q. Other than your attorney and me when we talked on the phone?

A. Yes, I don't recall.

Q. Okay. We might be down to one more document. This is 205.

[EXHIBIT 205 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. Miss Sullins, I don't know -- we're not going to go into too much detail here so once you've read the first three pages or so, probably -- okay.

A. I have read the first three pages.

Q. Okay. So tell me first of all, are you familiar with this document?

A. I am.

Q. Okay. Tell us a little bit about what's going on here.
A. There was a --
Q. I'm sorry, what number did I do this?
A. 205.
Q. Okay.
A. There was legislation that was passed in the 2011 General Assembly that required us to look at -- to implement tiered enforcement for different kinds of violations and to -- and to enable the use of notices of deficiencies in programs where they had not previously been used.
Q. What is a notice of deficiency?
A. It's telling someone that they're deficient in meeting the requirements of their permit.
Q. How is it different from a notice of violation?
A. In my opinion, it does not.
Q. It's the same thing, in your opinion?
A. In my opinion a deficiency is a violation.
Q. A distinction without a difference?
A. That's how I would classify it.
Q. So the Department was -- had put

together a uniform policy for these -- for notifications of deficiency and violations?

A. As required by the General Assembly.

Q. Okay. And then if we look at page 2 of this, it has these different tiers that the violations fit into. Is that kind of the heart of this is that you categorize different violations?

A. Yes.

Q. What was your involvement in this policy?

A. My involvement was to direct staff to collect information from a variety of other states to evaluate how other states were doing their enforcement, to have staff work on the Division's implementation, and provide feedback on the departmental policy.

Q. And so it sort of gives some idea of what would be considered Tier 1 violations; do you see that?

A. Yes, it does.

Q. And what are those?

A. Well, there's -- on page 11 it gives an example of Tier 1 violations for the Division of Water Quality, definition of the enforcement tiers.

Q. And actually it sounds like late

reporting is one?

A. Failure to meet schedules, minor operational deficiencies, minor design deviations, minor recordkeeping, failure to apply for renewal of a permit, failure to pay fees, inadequate maintenance, non repeat limit violations, well construction violations.

Q. And those are notice of deficiency violations; is that right?

A. That is correct.

Q. And then you bump up to the next level for notice of violation?

A. Yes.

Q. Okay. It says "notice of violation is normally issued for Tier 2 violations," and then enforcement actions I guess, notice of recommendation for enforcement for Tier 3; do you see that?

A. I do.

Q. Was this a -- so was this a change in approach by the Department to these issues?

A. Well, it was a change in approach that the legislature directed the Department to implement.

Q. Okay. But it was implemented by the Department; is that right?

A. Yes.

Q. And I think you said this idea of a notice of deficiency was kind of a new -- was that a new concept?

A. No, a notice of deficiency had been out there because when the animal waste program was developed, the legislature was specific in establishing the concept of a notice of deficiency for animal waste industry.

Q. Okay. Where would a -- I may have missed this, but does anyone -- is there a place in this memo that talks about where violations of 2L standards would fall in this?

A. I don't believe this memo is going to be that specific.

Q. You wouldn't consider that to be a Tier 1 violation, would you?

A. A 2L standards violation?

Q. Yes.

A. It doesn't appear to fall in the 13 categories.

Q. Did this policy, Miss Sullins, change? Was this -- did this have an impact on how DENR did things?

A. Yes.

Q. And can you just explain that? What comes to mind when -- what was most significant in changes?

A. Well, we weren't using notices in the Division of Water Quality specifically. I can't speak to the other divisions, but the Division of Water Quality was only using notices of deficiencies with respect to the animal waste facilities. We were not using the concept of a notice of deficiency across the program broadly.

So that changed our enforcement mechanisms that we were using and put another one into play that we had not been previously been using.

Q. Okay. Other than that new notice, anything else?

A. I don't recall that it altered other aspects of the enforcement program.

Q. Were there any policies in place that tried to do something similar to this that were in place when this came out?

A. That had tried to something similar to the notice of deficiency approach?

Q. Well, what I really mean is listed out, you know, the severity of different kinds of issues?

A. We had a draft penalty tree that we worked with that dealt with limit violations.

Q. I'm sorry, what kind of --

A. Limit violations, permit limit violations specifically to provide some guidance as to how those decisions were to be made and to keep some consistency across the state.

Q. Okay. Did those ever become an actual policy?

A. No.

Q. Why?

A. Not that I recall.

Q. Okay. Why was that; do you know?

A. There was discussion over whether those kinds of things should be rules.

Q. You mean, in other words, made subject to an administrative rule making procedure?

A. Yes.

Q. Was there that discussion around this or was it because this was mandated by statute that that issue didn't come up?

MR. ANDERSON: Objection.

A. This was mandated by statute.

Q. Let's take -- I'd like to take a five-minute break and just make sure I don't have anything else.

THE VIDEOGRAPHER: We're off the

record at 12:23 p.m.

[RECESS - 12:23 P.M. TO 12:30 P.M.]

THE VIDEOGRAPHER: We are back on the record at 12:30 p.m.

MR. WHEELER: All right, thank you. Miss Sullins, we don't have any further questions for you at this time.

THE WITNESS: Okay.

MR. WHEELER: Thank you.

CROSS-EXAMINATION

BY MR. ANDERSON:

Q. I guess it's still -- well, it's not morning. Good afternoon Miss Sullins. I introduced myself earlier. My name is Mark Anderson and I represent Duke Energy Progress. I just have what may be a fair number of followup questions for you on some of these issues.

I guess the first question would be prior to subpoenaing you here for your deposition today, did your former employer DENR give you access to all of the documents that they have pulled relative to your involvement with regard to groundwater monitoring during the years you were at DENR?

A. No.

Q. Were you aware that Mr. Tom Reeder has taken the position in this case on behalf of DENR that you, among other former DENR employees, quote, didn't do a damn thing with regard to the coal ash issue?"

MR. WHEELER: Objection.

A. No.

Q. Given that there has been an objection, I'll show what I've marked as Exhibit 206 to your deposition --

[EXHIBIT 206 WAS MARKED FOR IDENTIFICATION]

BY MR. ANDERSON:

Q. -- which are portions of the videotape deposition taken June 5, 2015 of Thomas Reeder, those pages that mention your name. And let me ask you first, do you know who Mr. Tom Reeder is?

A. I do.

Q. Was he at DENR during the time that you were there?

A. He was.

Q. If you would look at page 25, and feel free to look at any or all of it. First I was going to ask you about the names on page 25. Down at line 19 it begins some testimony "but why aren't they looking at these other people, Robin Smith." First of all, who is Robin Smith?

A. Robin was the Assistant Secretary for the Department specifically on environmental regulatory issues. She was my boss.

Q. And for how long was she with DENR, if you know?

A. I don't know. She came to DENR from the AG's office.

Q. Did she remain at DENR for some period of time after you left?

A. She did.

Q. And then next your name is listed. Following that who, how do you pronounce that, Chuck Wakild?

A. Chuck Wakild.

Q. Who is he?

A. He was the deputy director for the Division of Water Quality. He reported to me.

Q. And who is Rick Shiver?

A. Rick Shiver was the Wilmington office regional water quality, surface water quality protection supervisor.

Q. And how about Amy Adams?

A. Amy Adams was a staff in the division in the Washington regional office when I was with the Division. I believe she was promoted to regional supervisor water quality in Washington after I departed.

Q. With regard to DENR's attention to the issues that came up regarding coal ash during your tenure, you have today looked through some documentation, correct --

A. That's correct.

Q. -- exhibits to your deposition? Did DENR turn a blind eye to possible groundwater issues caused by coal ash during the period you were there?

A. I don't believe so.

Q. From your memory, either independently or as refreshed by these documents today, did DENR, in fact, devote a significant effort in its attempt to work with utilities to figure out what the possible issues were with regard to groundwater and how to address those for these coal ash ponds that had been situated for 40, 50 years?

A. Yes.

Q. You were shown a 2011 policy memo that had been previously marked as Exhibit 47. Is that still in front of you?

A. Yes.

Q. As far as you know, did DENR ever do anything to indicate to the regulated community that the policy as set forth in that memo was no longer the policy of the state of North Carolina with regard to managing these coal ash facilities?

MR. WHEELER: Objection.

A. I don't recall the -- I don't recall if there was any action along those lines in my tenure and I left six months after this was issued.

Q. When a policy memo like that is created, is it generally circulated to parties of interest in the regulated community?

A. Sometimes.

Q. If, in fact, that memo was circulated to Progress Energy and Duke Energy and others in the regulated community at the time it was developed, would you expect them to rely on it?

MR. WHEELER: Objection.

A. I certainly would expect them to rely on it.

Q. I believe you were asked some questions about whether that type of policy memo is in any way unusual for DENR. Within the aquifer protection section did DENR prepare and circulate to the regulated community a number of policies to address specific issues of concern?

A. I -- I don't know that I can answer that question specifically. DENR certainly, the Division of Water Quality certainly developed policies to address issues that arose in terms of the need to manage some issue on a statewide basis.

Q. I'm going to show you, for example, what we've marked for purposes of your deposition as Exhibit 206, a June 22nd, 2012 memorandum -- 207.

[EXHIBIT 207 WAS MARKED FOR IDENTIFICATION]

BY MR. WHEELER:

Q. This one, June 22nd, 2012 to Aquifer Protection Section Staff and interested parties from Ted L. Bush, Jr., Deputy Director of Division of Water Quality regarding the guidelines for the closure of permitted waste water ponds and lagoons. Do you recall seeing this particular memorandum?

A. No, because I was not there.

Q. In looking through this memorandum, does this, in similar fashion to the one we marked as an exhibit, outline policy statements and include as exhibits flow charts to demonstrate the manner in which DENR will implement the policies?

A. Yes, it certainly does.

Q. And I think you have told us with regard to some of these other memos, but why is it that DENR makes an effort to be consistent with regard to its interpretation and application of the rules to various members of the regulated community across the state?

MR. WHEELER: Objection.

A. The -- it is in the permittees' interest and the public's interest that the Division be consistent with its application of regulations.

Q. During the period of time that you were at DENR, was it stressed that in implementing the various laws and regulations of the State that DENR could not act in an arbitrary and capricious manner?

A. Absolutely we are not allowed to act in an arbitrary and capricious manner.

Q. And was it explained to you and, frankly, by you to members of your staff that it was necessary for all members of the regulated community who were similarly situated to be treated in the same fashion so as to avoid being arbitrary and capricious?

A. The purpose of policies and flow charts, et cetera, was an effort to assure that we were not arbitrary and capricious in our decisions and so the staff had the advantage of knowing how to process decisions and different situations.

Q. With respect particularly to groundwater and 2L exceedances, the information that we have received in this case would indicate that in the ten-year period prior to today, so prior to 2015, including within the time you were at DENR, that there has been no penalty, financial penalty, issued to an entity for 2L violations where that entity had not been offered the opportunity for corrective action; is that consistent with your memory?

A. I do not know the answer to that question.

Q. But from your personal experience you never were involved in issuing a penalty to an entity for a 2L violation of groundwater standards where they had not even gotten to the corrective action stage, correct?

A. I can't answer. I'm sorry, I don't recall.

Q. Just don't remember it?

A. No.

Q. Ask you about the policy memorandum now, the earlier one that was marked as 47 relating to groundwater and to --

A. Would you like me to mark this one 207?

Q. Please. Thank you.

[EXHIBIT 208 WAS MARKED FOR IDENTIFICATION]

BY MR. ANDERSON:

Handing you a document which we have marked for purposes of your deposition. I think you've got two of the Exhibit 5s as --

A. Two separate documents, correct or one?

Q. The second document is an exhibit to the first.

A. Okay.

Q. Exhibit 208 is a lawsuit filed in Superior Court Wake County, State of North Carolina versus Duke Energy Progress. I want to ask you if you would, and again you can feel free to review any of it, but if you could turn to page 10 at paragraph 37.

Paragraph 37 reads on "June 17, 2011 that DWQ adopted a policy for compliance evaluation of long-term permitted facilities with no prior groundwater monitoring requirements, hereinafter the policy for compliance evaluation. A copy of the policy for compliance evaluation is attached as Plaintiff's Exhibit Number 5, and is incorporated herein by reference."

If you could, would you please review Exhibit 5 to that lawsuit filed by DENR and determine whether that is the exact same policy which has been marked as Exhibit 47 in this litigation?

A. It appears to be the same policy. The attachment is copied in a different manner. It is the same policy.

Q. Do you see there that paragraph 39 includes the allegation by DENR that all six facilities are subject to the policy for compliance evaluation and on the top of the page it lists Sutton electric plant as one of the six facilities?

A. Yes.

Q. Do you have any reason to believe that as of August, and the sworn verification is on the very back, as of August 16th, 2013 DENR and its lawyers at the Attorney General had not determined that the policy Exhibit 47 is in fact the policy that applies to Sutton for the evaluation of that facility as related to groundwater issues?

A. I'm sorry?

MR. WHEELER: Objection.

A. Could you state that question again, please?

Q. I'll say it differently.

A. Thank you.

Q. Turning your attention back to the last page of this.

A. Yes.

Q. Do you see that this is sworn and subscribed as being truthful by Jeffrey Poupart. Do you know who Mr. Poupart is?

A. I do.

Q. And likewise on page 50 it is signed by a number of lawyers for the Attorney General's office; do you see that?

A. I see that.

Q. And at page -- back to page 10, paragraph 39 is an indication that the -- all six facilities are subject to the policy for compliance evaluation.

A. I see that.

Q. And my question is as of at least August 16th, 2013, do you have any reason to believe that this policy did not, in fact, apply to the compliance evaluation for the Sutton facility?

MR. WHEELER: Objection.

A. I do not.

Q. At page 48 of the complaint paragraph 195, paragraph 195 concludes a section beginning on page 47 with the heading Other Exceedances of the 2L Groundwater Standards at the Sutton Plant; do you see that?

A. I do.

Q. And at page 195 it indicates "as of August 2013, the DWR staff is working with the Defendant, Defendant being Duke Energy Progress, to determine if these exceedances are naturally occurring or if corrective action would be required;" do you see that?

A. I do.

Q. Making reference to the policy that you were asked about, Exhibit 47 in this case and the flow charts, can you tell us where we would be on this flow chart as of August 2013 if DENR allegation is true that at that point the staff was working to determine if the exceedances are naturally occurring or if corrective action will be required?

A. So it appears that they would be in the diamond that says results greater than naturally occurring concentration, question mark. Let me look at that again. Assuming that that had been reported to the Division, that the Division is in the process of determining if the exceedances are naturally occurring or if corrective action will be required. So it appears they're headed down the right side of the diagram.

Q. And as of August of 2013, if the

allegations of the lawsuit are true and accurate, they have only gotten to the first, what is that, a trapezoid?

A. First diamond.

Q. The first diamond, there you go. The first diamond on the far right of the flow sheet where dependent on whether the results are greater than naturally occurring concentration you go up no for continuing monitoring and yes down to verify results?

A. That is what it appears to be based on statement 195 taken in isolation, yes.

Q. Under the policy as enunciated in the June 17, 2011 memo, at what point in the treatment of these facilities does DENR indicate that a facility would be subject to an enforcement action which could include penalties?

A. It's a very hard diagram to read. It appears that you have to go down the chain of verifying the results to the bottom, shows impact to the -- from other on site activities. You could cross over on either the one above that or the very bottom one to come over to the determination that the facility is non compliant.

Q. It appears as if in that box, that rectangular box, facility is non compliant, permittee coordinates with Division regional office and implements corrective action plan in accordance with 15(a) NCAC-2L.0106.

That appears to be the same provision that is cited in these various memoranda that you have been shown today by counsel for DENR, correct?

A. Yes.

Q. And .0106 is the portion that provides for corrective action, correct?

A. I would have to see the regulations.

Q. I didn't bring it, but I can pull it up on the website just so we can be clear. I'll show you just for reference at least what the DENR website pulls up.

A. It's labeled corrective action.

Q. From -- and I know it's been a number of years, but --

A. It has been.

Q. But from your experience the provisions of 15(a) NCAC 2L.0106 corrective action are distinct from the provisions that allow for the assessment of a penalty, correct?

A. Yes, those are different.

Q. Okay. Under this policy as distributed to the regulated community, DENR had determined that prior to any enforcement action the permittee would be allowed to coordinate with DENR and implement corrective action in accordance with 15(a) NCAC 2L.0106, correct?

MR. WHEELER: Objection.

A. Yes, that is the way this flow chart reads.

Q. And from the exhibits which DENR lawyers have shared with you this morning, you have seen nothing to indicate that any of these utilities were advised anything to the contrary at any point, correct?

MR. WHEELER: Objection.

A. I have seen no documentation.

Q. All of the documentation that you have seen so far today would indicate that due to the particular nature of these long-term permitted facilities with no prior groundwater monitoring requirements that they would be subjected to a full assessment and then the potential for corrective action prior to getting to any penalty, correct?

A. The June 2011 memo certainly implies -- says that. The memorandum issued in October of 2011 establishes a process as well and I'm assuming that

DENR would work between these two memos.

MR. WHEELER: Can you just refer to the exhibit number there?

A. I'm sorry, Exhibit 205.

Q. And wanted to ask you about that. The Exhibit 205 in no way contradicts or revokes this memo relating specifically to the compliance evaluation of long-term permitted facilities, correct?

A. Exhibit 205 is a departmental process. It does not cite any of the other policy memos that may have been in existence at the time.

Q. And understanding you have now left DENR, but if DENR has through the Attorney General's office alleged in court in 2013 and continues to have the June 17, 2011 memo on its website for reference, would you expect that those would still be the policies that are meant to determine how these coal ash facilities are to be treated?

A. I would.

Q. When you were at DENR as relates to the prohibition against DENR acting in an arbitrary and capricious manner, was it also stressed that it was impermissible to subject one particular entity to enforcement in a manner that had never before been undertaken and never articulated?

A. I don't know that I can answer that question. If an issue came up that hadn't been dealt with previously, we would have to determine how to deal with it in a manner that we thought was not arbitrary or capricious.

Q. With respect to the manner which exceedances which I think you'll agree from the documents have shown were known as early as 2006, DENR worked through a lengthy process to set forth how those exceedances would be dealt with, correct?

A. Yes.

Q. One function of that I believe you indicated in your earlier testimony was that by virtue of the organizational structure of the State agencies, DENR would make regular reports to the Environmental Management Commission; is that right?

A. That is correct.

Q. And why is it that DENR would report to the Environmental Management Commission?

A. Because the Environmental Management Commission had requested it because it was an issue that dealt with implementation of the environmental management regulations.

Q. With regard to the issue as to whether you and others who preceded Mr. Reeder and Secretary Vandevart were turning a blind eye towards coal ash, while you were there was the process put in place to advise the Environmental Management Commission on a regular basis as to the manner in which these known exceedances around the coal ash ponds were to be handled?

A. We had -- we had put together a regular reporting process, yes.

[EXHIBIT 209 WAS MARKED FOR IENTIFICATION]

BY MR. ANDERSON:

Q. Showing you what I've now marked as Exhibit 209 to your deposition, which is a copy of a PowerPoint presentation given March 8th, 2012 to the Environmental Management Commission by Ted L. Bush, Chief Aquifer Protection Section, Division of Water Quality.

Now, this presentation was done after you had left the employment of DENR, correct?

A. That is correct.

Q. In walking through this presentation, as of the time you left at 2011 -- in 2011, was it usual and customary for the question related to the aquifer protection section for Mr. Bush or whoever was then the chief of that section to be the person who presented to the EMC?

A. Yes.

Q. And going through the presentation that was made by Mr. Bush in 2011, as of the time you were at DENR, were you aware that as of 2006 the utility industry in North Carolina had implemented a voluntary groundwater monitoring program?

A. Yes.

Q. And I believe you've touched on it before, but approximately three years after that, in December of 2009, the DWQ requested both utility companies to place wells at the compliance boundaries; is that right?

A. That's correct.

Q. And does the third slide in here illustrate the terminology with regard to compliance boundary, review boundary and application area that you described for us some this morning?

A. Yes.

Q. As it relates -- and feel free to flip through -- there are illustrations of typical power plant layouts, but as it relates particularly to the decision to include groundwater monitoring in the permits, how is that that decision was made?

A. I'm not sure that -- I'm not sure exactly how to answer that question. I mean, we had additional guidance from EPA over the scope of the NPDES program. I believe, I don't recall the specifics again, and worked with the companies in terms of getting agreement on having the well requirements into the permits.

We typically would have worked with the companies to discuss them, even if the companies didn't necessarily agree with our decision. I don't recall that we discussed it at the EMC.

Q. Do you remember any discussions about how that would work in terms of these issues of enforcement and potential penalties in the context of these wells where it was known at the time the monitoring was put into the permit that there were already known exceedances of 2L standards at the compliance boundary?

A. Can you you state that question for me again?

Q. Yeah. You were -- in terms of the NPDES that was kind of your role, one of your primary roles of writing those permits, correct?

A. Many years ago. I was the supervisor over the staff who wrote those permits.

Q. Can a permit be issued if the data already demonstrates that the facility is non compliant?

A. Yes.

Q. How does that happen?

A. The -- at some times the permit will be issued with a compliance schedule internal to the permit in order for the facility to come into compliance. Sometimes a permit will be issued and an order will be issued simultaneously that has a schedule for the permittee to come into compliance.

Q. Do you recall, and in particular I'm talking about the Sutton plant now, any discussions about how the 2L exceedances at the compliance boundary were to be treated in connection with the permit renewal that became effective January 1, 2012?

A. I don't believe I was involved in those discussions, but that could be I'm just not remembering. I do not remember.

Q. Even if your name was on the issuance of a permit you don't remember any discussions?

A. My name being on the issuance of the permit is a common factor. It was on the issuance of every permit normally signed for me by some other member of the staff.

Q. If I could get you to look at slide 11 from the March 8, 2012 PowerPoint. There's an indicator here "groundwater sampling results," the first bullet, "both utility companies have now completed two to four sets of groundwater sampling for each facility and two reports of modeling and it lists all the various exceedances that have been found as of that point."

Based on what you do remember about your time at DENR as refreshed by the documents this morning, was it clear that as of 2011, there were 2L exceedances found in the monitoring wells around these coal ash ponds throughout the state?

A. Yes, it was clear that there were exceedances.

Q. And as you look at two pages over, the next page there's a -- should be a white page with a graph that states "common exceedances 14 total facilities," and the first bar graph is iron and manganese. Would it be at all surprising for there to be exceedances of 2L standards in, frankly, any well around North Carolina for iron and manganese?

A. Those are fairly common materials found in soils of North Carolina, so it would be common for those to be found.

Q. And as you go to the next page there is a graph with total number of wells with exceedances and then the next page most common parameter exceedances. After you get through the data slides there is a page, another blue page, groundwater monitoring at coal ash facilities. And in the yellow bullet is when exceedances are reported, APS requires staff to consider and it lists four categories.

Is the information being reported here consistent with what you have reviewed today in the various policies that were promulgated by DENR during the period of time?

A. It is.

Q. And likewise, on page 19 of the presentation the bullets indicate that APS staff staff is requiring utility companies to determine whether or not exceedances are violations. Is that consistent with what was articulated in the policy memorandum?

A. It is.

Q. And again, it indicates that if violations are confirmed, action will be taken in accordance with 15(a) NCAC 2L .0106; that means corrective action, true?

A. That is what that regulation references, yes.

Q. And in terms of the policy for dealing with the known exceedances at these facilities, it was very clear as of that time that DENR's position was that due to the nature of these long-term permitted facilities what would be required was a full assessment and corrective action, true?

MR. WHEELER: Objection.

A. The DENR policies established that there will be a full assessment, corrective action and determination as to the appropriate action.

Q. When DENR had policies with regard to other types of water issues that provided for penalties and enforcement actions, those were specified as well, correct?

A. I'm sorry, ask that question again.

Q. Sure. What did DENR do, for example, with discharges into streams or other areas that could lead to a penalty and enforcement action?

A. We would do a number of things, issue a notice of violation, issue a civil penalty. It would depend on the situation.

Q. When a civil penalty was permitted prior to corrective action, that was something that was articulated in the policy and the regulations, correct?

A. It was not articulated in the regulations per se. It was articulated more through policy.

Q. Assuming the allegations of the complaint at Exhibit 208 verified by Mr. Poupart to be accurate, that as of August 2013 DWR staff is working with the Defendant to determine if these exceedances are naturally occurring or if corrective action will be required, at that point under the policy even an NOV is not appropriate, correct?

MR. WHEELER: Objection.

A. Under the policy an NOV would not be issued.

Q. And it absolutely would be inappropriate to work backwards and attempt to fine one of these facilities for one of the 2L exceedances which had occurred three to four years prior to that date, correct?

MR. WHEELER: Objection.

A. I don't know that I understand when the exceedance occurred that a notice of violation or civil penalty was issued for. I just don't know the facts around that.

Q. Based on what you have been shown by DENR's lawyers and what we've looked at today, it would be entirely inappropriate for DENR to go back and issue a penalty for a day in 2009, three years before this allegation was made, correct?

MR. WHEELER Objection.

A. I don't know the circumstances around DENR's decision to issue a penalty. I would say that the policies in place and DENR's certification, is that the proper term?

Q. Verification.

A. Verification as to how the policies would be implemented would dictate the outcome of a decision.

Q. You had in earlier testimony indicated that DENR, at least when you were there, relied on individuals in the regional offices to be most familiar with the sites in their region; is that correct?

A. That is correct.

Q. And why is that?

A. Because they're the staff who are there on a day-to-day basis. They are the staff who respond to emergencies. They're the staff who go out and do inspections specifically for purposes of making determinations.

They typically are the staff who review the compliance documents and are the staff who make recommendations and provide input to the central office staff on decisions.

Q. Did Morella Sanchez King come to DENR prior to you leaving?

A. I do not recognize the name.

Q. During the period of time that you were in DENR, was there training provided to members of the staff with respect to how enforcement was to be done, compliance and enforcement training?

A. Yes.

Q. Show you what's been marked as an exhibit to one of the earlier depositions as Exhibit 8, this one from a May of 2008 presentation entitled Compliance and Enforcement Training.

And I'll represent to you that there are in the documents that we've been provided numerous versions that look somewhat similar for training that was provided do people at DENR.

Have you ever seen a -- well, I guess I can ask you specifically. Are you familiar with this specific training presentation?

A. I don't remember the specific training that is provided here. The different branches and different sections would put training on for the regional office staff. I was not typically involved in those, in that training.

In 2008, I'm trying to remember when I went into what role. In 2008, I believe I was the director so I wouldn't -- I mean, I would have said to the sections you need to develop training associated with implementing enforcement for the programs that are under your jurisdiction.

Q. Going forward during your time at DENR, did you ever see any similar training programs where the specific slides, including these last two, assessment factors, penalty amounts, were presented where in QA fashion it was posed can we assess 25,000 per day per violation as it says in all our templates and the answer is but no, the answer we have to live with based on the Murphy farms lagoon breach case?

A. Uh-huh. I mean, yes.

Q. When you were there, that's the way you trained people, that you can't assess somebody for a fine for every single day, correct?

A. If I remember the Murphy farm case, that was the case where the dissolved oxygen was below standard for repeated days in a row, but there was an incident that had occurred, a breach that had occurred, that caused that violation. And I believe the outcome, the case law from that was that we could only assess for the breach.

Q. And that is how at least when you were there DENR staff members were trained?

A. It's certainly how we had to implement the regulations we had been advised through the legal process.

Q. During the time when you were with DENR, can you recall any instance when DENR attempted to look backwards and fine an entity for an alleged violation for 365 days a year over a period of several years?

A. I don't recall any violation that the Division of Water Quality, let me be specific about this, that the Division of Water Quality issued where there had been a violation and that the Division looked back in terms of making that decision.

The Division would look back and look at the history of compliance and the history of compliance 365 days prior to a decision to take an enforcement action would be taken into consideration.

Q. In determining whether or not enforcement action would occur, correct? History of compliance is one of the eight factors.

A. History of compliance is one of the eight factors. It also is a factor in the degree of assessment.

Q. But in terms of groundwater you have no specific recollection of a financial penalty ever being assessed against an entity during the period of time when you were at DENR, correct?

A. I'm not sure I agree with that statement. I believe there were penalties assessed for groundwater violations, but so I'm not sure I agree with the way you phrased that question. I don't specifically recall enforcement cases, but I don't specifically recall either that there was never an enforcement case for groundwater standards violation.

Q. They would be related to corrective actions, as far as you can recall?

A. I just don't recall.

Q. Do you recall becoming personally familiar with sites located in the area surrounding the Sutton steam plant that had contaminated aquifer?

A. I don't.

Q. Were you involved in any way in assessing what should be done with the Flemington landfill?

A. No, not that I recall.

Q. Were you involved in any way in the determining what should be done with the Invista site?

A. I don't think so. What was Invista before it became Invista?

Q. Lots of names.

A. Yes.

Q. Hercules?

A. I don't think I was involved in any of the Hercules stuff.

Q. Cape Industries?

A. Yeah, I mean, I remember the names and I remember there were lots of issues, but I don't think I was personallly involved in any of those.

Q. Maybe I can try with some summary questions without going through back through these lines. If we need to get them out, we will, or feel free to look at the various exhibits if you need to refresh your memory.

Trying to get an understanding of your own personal involvement and memory as to the work done during the period beginning around 2006 and up through and after the time that you left DENR to work with the utility companies to determine how groundwater standards were to be applied for these existing coal ash basins.

Do you recall sitting in on any of those meetings?

A. I recall being involved in at least one of those meetings, but I believe this is one of the items that I passed off for management of it to Chuck and the section chiefs. I don't believe I was involved in all the meetings associated with this. That is my recollection.

Q. From your recollection, would Ted Bush who issued that memo, Debra Watts and others working in that area be the most familiar with what ultimately was determined to be the policy of DENR to be applied for these cases?

A. Yes.

Q. And did you in your supervisory role get some information back from them that the regulated community, in particular the two utilities, wanted to be very clear as to how DENR was going to address these issues moving forward?

A. Well, the utilities certainly wanted to have input and wanted clarity on how issues were to be decided. And we would discuss -- internal to the staff we would have discussions about how those things were proceeding and we would also have discussions prior to every presentation that we made as to how things were proceeding.

Q. In terms of internal to the staff, it was very clear to DENR that the utilities wanted clarity as to whether these known exceedances at the compliance boundary were going to be met with penalty and enforcement action rather than corrective action and the ultimate remediation to the site, correct?

A. Well, the utilities definitely wanted the first line to be corrective action and a response to that and not to be penalty. They were very clear about their positions.

Q. And that's what DENR ultimately decided to do, correct?

A. That is what the memos ultimately captured, yes.

Q. And had it -- had the policy been different that the first line was going to be penalty, that's something the utilities should have been told, correct?

MR. WHEELER: Objection.

A. The utilities certainly would have been told if that was the way that DWQ was going to proceed in those matters.

Q. But that absolutely was not the case that DWQ was going to proceed with penalty before the opportunity for corrective action, true?

A. The memos are laid out for DWQ to proceed with corrective action. Again, I don't know the facts surrounding the case and there's always a reason why something may need to be considered outside of a policy.

Q. It would be inappropriate to take an action outside of the clearly enunciated policy merely for public relations purposes, correct?

MR. WHEELER: Objection.

A. In my opinion it would be inappropriate to take any enforcement action for public -- how did you phrase that?

Q. I said public relations reasons.

A. Public relation reasons, thank you.

Q. And I guess put bluntly, politics shouldn't enter into an enforcement action in the regulated community, should it?

A. Politics should not enter into it.

Q. Since the decision was made to issue a $25.1 million penalty relative to these 2L exceedances at Sutton, have you spoken to Debra Watts, Ted Bush or any other of the individuals at DENR to determine who in the world made that decision?

A. I have not spoken to anyone about the penalty, nor was I aware of the size of it.

Q. If you could give me five minutes. Let me talk to my lawyers over there and I'll see whether I'm finished.

A. Okay.

THE VIDEOGRAPHER: Off the record at 1:33 p.m.

[RECESS - 1:33 P.M. TO 1:34 P.M.]

THE VIDEOGRAPHER: We're back on the record at 1:34 p.m.

MR. ANDERSON: Ma'am, I appreciate your time. I have no further questions.

REDIRECT EXAMINATION

BY MR. WHEELER:

Q. Just a few followup questions.

A. All right.

Q. So Mr. Anderson showed you this Exhibit 209, this PowerPoint, and I just want to direct your attention to slide 19. So that -- what does that first bullet point say?

A. "APS staff is requiring utility companies to determine whether or not exceedances are violations."

Q. To your knowledge, did utility companies, Progress or Duke, ever tell DENR whether they'd determined if their exceedances were violations?

A. I don't know. This is after my -- after I left. I do not know.

Q. Did you ever hear that they had done that?

A. No, I don't recall ever hearing that.

Q. As we sit here today, do you know if they have ever done that?

A. I don't know.

Q. And you were also asked about when these groundwater monitoring steps started being taken; do you remember that?

A. Yes.

Q. I think the Figure 2006 came into mind?

A. I believe that's correct.

Q. And then we had looked at documents earlier that showed Mr. Stehman talking about exceedances in I think it was the 2009 time frame; do you remember that?

A. I believe that's correct.

Q. And then 2010 again?

A. Possibly.

Q. Okay.

A. I remember the 2009 email.

Q. Okay. And then Mr. Anderson showed you this brief that was filed in court in 2013, so I guess that's, I don't know, about two years ago?

A. Right.

Q. And the language says that "DWR staff is working with the Defendant to determine if these exceedances are naturally occurring or if corrective action will be required;" is that correct?

A. That is correct.

Q. Does that help you figure out whether Duke has informed DENR whether it's determined that the exceedances are violations at that point?

A. The documents certainly all imply that the evaluation is still ongoing as of 2013.

Q. And that's after approximately seven years?

A. The initial monitoring after seven years after --

Q. 2006.

A. Yes.

Q. And we've looked at the chart on -- the flow chart on the back of the policy?

A. Yes.

Q. And would you characterize that as making -- was that close to -- that chart close to being completed or was that sort of towards the beginning of the steps being taken there?

A. It certainly appears to still be being close to the beginning of the steps being taken.

Q. You said something, this is paraphrasing, but you said in response to a question that there's a reason why something may need to be considered outside of a policy; do you remember saying that?

A. I do.

Q. And is that similar to the idea of discretion, DENR's discretion in issuing a notice of violation?

MR. ANDERSON: Objection.

A. Yes.

Q. And is that the discretion we talked about that you identified in the policy we looked at, the Ted Bush policy, Exhibit 47?

A. Let me look at Exhibit 47.

Yes.

Q. In your experience at DENR were the events of 2014 involving Duke Progress unusual?

A. The events of 2014?

Q. I'm specifically referring to the Dan River accident and then the subsequent criminal prosecution.

A. Yes, they were unusual.

Q. Had you ever seen anything like that before?

A. No, I can't say that I've seen anything quite like that.

Q. And in connection with that criminal prosecution Duke was fined in excess of or approximately a hundred million dollars; does that sound right?

A. I didn't track that.

MR. WHEELER: I don't have any other questions.

RECROSS-EXAMINATION

BY MR. ANDERSON:

Q. Actually, just a few followup based on that, apologies.

You indicated earlier that you actually testified in the Alcoa case, correct?

A. I did, I think.

Q. You did testify that you gave a deposition in that case?

A. Yes.

Q. And did you end up seeing the opinion in that case?

A. Did I end up seeing an opinion in that case, in that case I revoked a decision that I made so that stopped that case. Because I -- we were defending a decision I had made. And I revoked it based on testimony that was provided in that case.

Q. You were asked about a seven-year process for a site like Sutton. I need to ask you based on your experience if DENR's own expert, Bill Deutsch (phonetic) a geochemist, sat in that seat on Friday and testified that it is not unusual in a complicated site for it to go approximately ten years from the initial sampling exceedances through the site assessment to move towards corrective action, do you have any reason to dispute that that period of time is a reasonable period of time to get a full site assessment and to move into a corrective action?

A. I don't.

Q. You were asked about Dan River. You're familiar enough with the coal ash sites in North Carolina to know that Dan River has nothing to do the Sutton steam plant; correct?

A. That's correct.

Q. And also aware that Sutton at the time of the decision around how plants were to be monitored for groundwater was a Progress Energy plant and not a Duke Energy plant, correct?

A. That is correct.

MR. ANDERSON: Thank you. No further questions.

FURTHER REDIRECT EXAMINATION

BY MR. WHEELER:

Q. One followup question. The -- the federal criminal case where you -- let me strike that.

Do you know whether the federal criminal case involved facts related to Sutton?

A. I don't.

Q. Would it surprise you to learn that it did?

MR. ANDERSON: Objection.

A. No.

MR. WHEELER: Okay. Nothing further.

FURTHER RECROSS EXAMINATION

BY MR. ANDERSON:

Q. Just ask one more. I just need to ask one more thing, based on that. You're aware of no authority, DENR or otherwise, that stands for the proposition that a fine in a criminal case is a basis for a civil groundwater penalty, are you?

A. I'm not.

MR. ANDERSON: Thank you.

THE VIDEOGRAPHER: This concludes the videotape deposition of Coleen Sullins. We're off the record at 1:44 p.m.

[DEPOSITION ADJOURNED AT 1:44 P.M.]

I have read the foregoing pages which contain a correct transcription of the answers given by me to the questions herein recorded. My signature is subject to corrections on the attached errata sheet, if any.

Signed this _____ day of _______________, _______.

____
COLEEN SULLINS

STATE OF __________________
COUNTY OF _________________

Subscribed and sworn to before me this _______ day of ___________________, ________.

____
Notary Public

My commission expires:

____

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Marian E. Cummings, notary public/court reporter, do hereby certify that the above-named was duly sworn or affirmed prior to the taking of the foregoing deposition; and that said deposition was taken and transcribed under my supervision; and that the foregoing pages, inclusive, constitute a true and accurate transcription of the testimony of the witness.

I do further certify that the persons were present as stated in the caption.

I do further certify that I am not of counsel for or in the employment of either of the parties to this action, nor am I interested in the results of this action.

This is the 26th day of August, 2015.

Marian E. Cummings

Notary Public #201125500083

year	years from 2014					
1989	26					
			Total Cost	$	405,957,531.00	
			Remove Charah	$	(46,329,946.00)	
			Remove Water Supply	$	(17,527,070.00)	
			Revised Cost	$	342,100,515.00	
		171,500,000	0.027		$342,843,293.06	Net Present Value of Approx. $342000000 over 26 years at average interest rate of 2.7% is approxiamtely the Revised Cost
					$171,343,293.06	Difference Between Revised Cost and Equivalent Cost 26 Years Earlier
				$	188,870,363.06	Add Back in Water Supply Cost Requested of $17527070 to determine total decrease
1995	20		Total Cost	$	405,957,531.00	
			Remove Charah	$	(46,329,946.00)	
			Remove Water Supply	$	(17,527,070.00)	
			Revised Cost	$	342,100,515.00	
		218,000,000	0.023		$343,533,558.33	Net Present Value of Approx $342000000 over 20 years at average interest rate of 2.3% is approxiamtely the Revised Cost
					$125,533,558.33	Difference Between Revised Cost and Equivalent Cost 20 Years Earlier
				$	143,060,628.33	Add Back in Water Supply Cost Requested of $17527070 to determine total decrease
2003	12		Total Cost	$	405,957,531.00	
			Remove Charah	$	(46,329,946.00)	
			Remove Water Supply	$	(17,527,070.00)	
			Revised Cost	$	342,100,515.00	
		263,500,000	0.022		$342,130,166.81	Net Present Value of $342000000 over 12 years at average interest rate of 2.2% is approxiamtely the Revised Cost
				$	78,630,166.81	Difference Between Revised Cost and Equivalent Cost 12 Years Earlier
				$	96,157,236.81	Add Back in Water Supply Cost Requested of $17527070 to determine total determine total decrease
2010	5 yrs					
			Total Cost	$	405,957,531.00	
			Remove Charah	$	(46,329,946.00)	
			Remove Water Supply	$	(17,527,070.00)	
			Revised Cost	$	342,100,515.00	
		312,906,680	0.018	$	342,100,512.39	Net Present Value of $342000000 over 5 years at average interest rate of 1.8% is approxiamtely the Revised Cost
				$	29,193,832.39	Difference Between Revised Cost and Equivalent Cost Five Years Earlier
				$	46,720,902.39	Add Back in Water Supply Cost Requested of $17527070 to determine total to be substracted from cost recovery request

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Yearly Avg Inflation Rate			
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%	2.68%	1989	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%	2.33%	1995	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%	2.24%	2003	2014
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%	1.79%	2010	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%			

I/A

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

APPEARANCE OF COUNSEL:

By Videoconference For Duke Energy Carolinas, LLC and Duke Energy Progress, LLC:

KIRAN H. MEHTA, Esq.
MELISSA O. BUTLER, Esq.
Troutman Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202
(704) 998-4072
Kiran.mehta@troutman.com
Melissa.butler@troutman.com

By Videoconference For Public Staff - NC Utilities Commission

NADIA L. LUHR, Esq.
Public Staff - N.C. Utilities Commission
430 N. Salisbury Street, Suite 5060
4326 Mail Service Center
Raleigh, North Carolina 27699-4300
(919) 733-0975
Nadia.luhr@psncuc.nc.gov

By Videoconference for NC DOJ:

TERESA L. TOWNSEND, Esq.
MARGARET A. FORCE, Esq.
North Carolina Department of Justice
114 W. Edenton Street
Raleigh, North Carolina 27603
(919) 716-6980
Ttownsend@ncdoj.com
Pforce@ncdoj.com

Also present:

MARTIN NOBREGA, Videographer
TIRRILL MOORE, Esq.
CAMAL ROBINSON, Esq.
KEVIN O'DONNELL
MEREDITH HAGGERTY
EMILY MEDLIN, Esq.
KEVIN MARTIN

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.

CONTENTS

INDEX OF EXHIBITS

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

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 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 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

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

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.

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.

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 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

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

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

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 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

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?

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

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

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

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.

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

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

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?

WEDNESDAY, MARCH 9, 2016 | $1 | FOUNDED 1886 VOLUME 147, No. 69 | FACEBOOK.COM/THECHARLOTTEOBSERVER TWITTER.COM/THEOBSERVER | READ BY 1 MILLION+ IN PRINT AND ONLINE | Partly cloudy 77°/54° See 26A

The Charlotte Observer

CHARLOTTEOBSERVER.COM

WATER QUALITY

State lifts warnings on well water near ash ponds

Nearly 400 neighbors on bottled water since last spring

Some say they're not sure water is safe to drink

Contaminants cited in advisories are similar to levels in public water systems

BY BRUCE HENDERSON
bhenderson@charlotteobserver.com

Nearly a year after advising hundreds of residents who live near Duke Energy's coal ash ponds not to drink their well water, state health officials abruptly reversed course Tuesday.

The N.C. Department of Health and Human Services said it would rescind advisories issued last spring after tests found elevated levels of vanadium and hexavalent chromium in private wells.

Both occur naturally and in coal ash. Duke says it is not responsible for the contaminants but has supplied residents with bottled water since then.

Many of the 369 advisories went to well owners in Gaston and Rowan counties, and some say they're still not convinced their water is safe.

Amy Brown, an outspoken Belmont neighbor of the Allen power plant, said only a permanent solution – water filters or a connection to city water lines – would give her peace of mind.

"How can my water be unsafe yesterday but today, with the standards still the same, you want to tell me my water is now safe?" she said. "I don't feel that anyone has given me any information for me to not fear my water."

Lifting the advisories may do little to ease fears that have enveloped Duke's neighbors for months.

"They've already scared people, and it's hard to unscare scared people," said Tad Helmstetler, Rowan County's environmental health manager. Helmstetler, who works closely with neighbors of Duke's Buck power plant, had received no word from Raleigh of the

SEE WATER, 2A

I/A

FROM PAGE 1A

WATER

change.

The state health agency said the change was driven in part because similar levels of vanadium and hexavalent chromium occur in public water supplies, including Charlotte's, at levels considered safe. Recent tests have also found the elements in groundwater far from ash ponds.

The agency also said safety standards for those elements are likely to change.

"Using an abundance of caution, we issued low (screening) levels that we knew were low levels," said Dr. Randall Williams, the state health director, who joined the department in July after the screening levels had been set. "But we're also humble enough to revisit them and decided that, based on new information, we felt it was appropriate to change them."

The don't-drink advisories were based on temporary screening standards that the department developed under the state coal-ash law. North Carolina has no groundwater standard for vanadium. A standard for chromium is meant to reflect its hexavalent form.

The state's health and environmental departments sparred for months over the screening levels, internal emails showed, with the environmental agency warning they were too stringent. The departments eventually agreed.

Neither the federal government nor most other states have set standards for hexavalent chromium, which is of particular concern because it may cause cancer. The exception is California, whose standard is much higher than the North Carolina screening level.

DHHS' decision to lift the don't-drink advisories followed a meeting Monday in Lee County, where coal ash will be disposed of in a former clay mine. Hexavalent chromium and vanadium have been detected in wells.

The department told county officials that they would take back earlier

THE STATE PLANS TO RECOMMEND A GROUNDWATER STANDARD FOR VANADIUM OF 20 PARTS PER BILLION, FAR HIGHER THAN THE 0.3 PPB LEVEL USED IN ASSESSING THE WELLS UNDER A COAL-ASH LAW.

advisories in Lee County and other parts of the state, the Fayetteville Observer reported.

The state Department of Environmental Quality plans to recommend a groundwater standard for vanadium of 20 parts per billion, far higher than the 0.3 ppb level used in assessing the wells, Williams said.

The Environmental Protection Agency, which regulates only total chromium in drinking water, is reviewing whether to issue a separate standard for its hexavalent form.

"We do not think it's fair to single out ... well owners in 12 counties to recommend that they not drink their water" in light of changing standards and the elevated levels found elsewhere, Williams said.

Duke said bottled water deliveries will continue for the time being. The company says that its ash isn't contaminating private wells but that it supplied water to give neighbors "peace of mind" as testing continued.

"We hope this is welcomed news to well owners, but it's terribly unfortunate the state took almost a year to give them certainty that their water is safe to drink," spokeswoman Paige Sheehan said.

Bruce Henderson: 704-358-5051, @bhender

NC lifts warnings against drinking well water near Duke Energy ash ponds

By Bruce Henderson

bhenderson@charlotteobserver.com

March 8, 2016

Nearly a year after advising hundreds of residents who live near Duke Energy's coal ash ponds not to drink their well water, state health officials abruptly reversed course Tuesday.

The N.C. Department of Health and Human Services said it would rescind advisories issued last spring after tests found elevated levels of vanadium and hexavalent chromium in private wells.

Both occur naturally and in coal ash. Duke says it is not responsible for the contaminants but has supplied residents with bottled water since then.

Many of the 369 advisories went to well owners in Gaston and Rowan counties, and some say they're still not convinced their water is safe.

Amy Brown, an outspoken Belmont neighbor of the Allen power plant, said only a permanent solution – water filters or a connection to city water lines – would give her peace of mind.

"How can my water be unsafe yesterday but today, with the standards still the same, you want to tell me my water is now safe?" she said. "I don't feel that anyone has given me any information for me to not fear my water."

Lifting the advisories may do little to ease fears that have enveloped Duke's neighbors for months.

"They've already scared people, and it's hard to unscare scared people," said Tad Helmstetler, Rowan County's environmental health manager. Helmstetler, who works closely with neighbors of Duke's Buck power plant, had received no word from Raleigh of the change.

The state health agency said the change was driven in part because similar levels of vanadium and hexavalent chromium occur in public water supplies, including Charlotte's, at levels considered safe. Recent tests have also found the elements in groundwater far from ash ponds.

The agency also said safety standards for those elements are likely to change.

"Using an abundance of caution, we issued low (screening) levels that we knew were low levels," said Dr. Randall Williams, the state health director, who joined the department in

July after the screening levels had been set. “But we’re also humble enough to revisit them and decided that, based on new information, we felt it was appropriate to change them.”

The don’t-drink advisories were based on temporary screening standards that the department developed under the state coal-ash law. North Carolina has no groundwater standard for vanadium. A standard for chromium is meant to reflect its hexavalent form.

The state’s health and environmental departments sparred for months over the screening levels, internal emails showed, with the environmental agency warning they were too stringent. The departments eventually agreed.

Neither the federal government nor most other states have set standards for hexavalent chromium, which is of particular concern because it may cause cancer. The exception is California, whose standard is much higher than the North Carolina screening level.

DHHS’ decision to lift the don’t-drink advisories followed a meeting Monday in Lee County, where coal ash will be disposed of in a former clay mine. Hexavalent chromium and vanadium have been detected in wells.

The department told county officials that they would take back earlier advisories in Lee County and other parts of the state, the Fayetteville Observer reported.

The state Department of Environmental Quality plans to recommend a groundwater standard for vanadium of 20 parts per billion, far higher than the 0.3 ppb level used in assessing the wells, Williams said.

The Environmental Protection Agency, which regulates only total chromium in drinking water, is reviewing whether to issue a separate standard for its hexavalent form.

“We do not think it’s fair to single out ... well owners in 12 counties to recommend that they not drink their water” in light of changing standards and the elevated levels found elsewhere, Williams said.

Duke said bottled water deliveries will continue for the time being. The company says that its ash isn’t contaminating private wells but that it supplied water to give neighbors “peace of mind” as testing continued.

“We hope this is welcomed news to well owners, but it’s terribly unfortunate the state took almost a year to give them certainty that their water is safe to drink,” spokeswoman Paige Sheehan said.

Bruce Henderson: 704-358-5051, @bhender

I/A

THURSDAY, JANUARY 14, 2016 | $1 | FOUNDED 1886 VOLUME 147, No. 14 | FACEBOOK.COM/THECHARLOTTEOBSERVER TWITTER.COM/THEOBSERVER | READ BY 1 MILLION+ IN PRINT AND ONLINE | Sunny 55°/36° See 12B

The Charlotte Observer

CHARLOTTEOBSERVER.COM

ENVIRONMENT

Conflicting standards on drinkable water probed

Contaminants deemed risky in wells but safe in public water

Chemical in question figured in 'Erin Brockovich' movie

Residents near Duke power plants still on bottled water

BY BRUCE HENDERSON
bhenderson@charlotteobserver.com

Legislators probed a question Wednesday that has bedeviled regulators and hundreds of North Carolina households: How can contaminants that are deemed safe in public water systems be labeled risky in private wells?

The state Health Department last spring advised more than 400 well owners, neighbors of Duke Energy power plants, not to drink their water. Most warnings cited detections of two substances that might come from Duke's coal ash ponds.

But similar levels of the contaminants, hexavalent chromium and vanadium, also appear in the municipal water of Charlotte, other North Carolina cities and across the United States. That water is judged safe to drink under federal standards.

"We're telling people that their water is unsafe, and now we're telling them that maybe it might not be," Sen. Andrew Brock, R-Mocksville, said as the Environmental Review Commission met Wednesday. "Nothing gets more personal than messing with somebody's water."

The state's environment and health agencies sparred for months, internal records show, over how to assess contaminants in private wells in the absence of relevant standards.

Officials worried most about hexavalent chromium, a form of the metal that may cause cancer in people who drink tainted water. Hexavalent chromium figured in "Erin Brockovich," the 2000 movie based on real-life groundwater contamination in California.

SEE WATER, 2A

FROM PAGE 1A

WATER

Research and the understanding of acceptable levels of toxic substances in the environment is evolving.

In 2008, the Environmental Protection Agency began considering whether to set limits on hexavalent chromium. The EPA has called it likely to cause cancer in humans if ingested in drinking water because of tumors found in rats and mice, and because of some evidence of stomach cancers in humans.

But North Carolina, like the federal government, has set no limit on how much hexavalent chromium in drinking water is safe.

In North Carolina, as officials prepared to test nearly 500 wells near Duke's power plants, they needed a benchmark by which to compare results. The Department of Health and Human Services used its own calculations: the level that might cause one cancer in 1 million people over a lifetime of exposure.

Department of Environmental Quality officials expressed alarm that the newly calculated screening level for hexavalent chromium in wells, 0.07 parts per billion, was too tough. Public water systems have only to meet a far higher federal standard for total chromium of 100 ppb, which includes hexavalent chromium.

Conflicting standards, DEQ argued, would mislead the public.

"Directing people to undertake certain mitigating activities with perhaps negligible health benefit is very different than alerting them to their risk in an understandable way," Jessica Godreau, chief of the state's public water supply section, wrote another DEQ official last March.

DEQ eventually consented to the tougher standard. While 424 of 476 well owners got don't-drink advisories, only 12 wells broke federal water standards.

Nearly a year later, Assistant Environment Secretary Tom Reeder told the commission, "It's incredibly confusing to the consumer."

"Decide which agency is in charge," said Sen. Ronald Rabin, a Harnett County Republican. "It can't be two different agencies in charge of water or it's chaos."

JOHN D. SIMMONS Charlotte Observer File photo

The state probe of Duke's groundwater contamination followed a 2014 ash spill into the Dan River.

MUNICIPAL, PRIVATE WATER

Health officials say they followed protocol in developing the screening levels on which their recommendations were based.

"One reason it's complex is that we have municipal water, groundwater, new wells and old wells. You'll hear different (standards) for all those things," said Dr. Randall Williams, deputy secretary of health services. "We're aware that different agencies and different parts of the government look at each of these four entities in different ways."

While public systems have to comply with federal standards, private well owners are essentially on their own to ensure their water is safe. The state investigation of Duke's groundwater contamination followed a 2014 ash spill into the Dan River and state legislation that ordered a broader look at ash issues.

The health agency will reassess its recommendations when more groundwater test data are reported in the next month, he said.

Amy Brown, a neighbor of Duke's Allen plant in Gaston County, said she appreciated Williams' personal visit after Christmas. But after eight months on bottled water, she added, her neighborhood is "in limbo. We have no real answer. We can't sell our houses. And we didn't ask for this, not one bit of it."

Duke says groundwater data indicate the well contaminants come from natural sources, not ash ponds.

Similar levels of hexavalent chromium and vanadium occur in soil and rock miles from ash ponds, Duke says. With one exception, it says, the boron that serves as an indicator of ash has not been found in private wells.

"We strongly agree that clarity is needed on state drinking water standards so plant neighbors and others across the state who have been told not to drink their water get this issue resolved soon," spokeswoman Erin Culbert said by email.

'CONSERVATIVE' STANDARD

Hexavalent chromium is used to make stainless steel and tan leather and to preserve wood. Pacific Gas & Electric, which settled a class-action lawsuit over groundwater contamination in California, used it to reduce corrosion at a power plant.

North Carolina officials, in calculating a screening level for the substance, relied on California's work with hexavalent chromium.

In 2011, California set the nation's first "public health goal" for hexavalent chromium in drinking water: 0.02 ppb, even lower than North Carolina's screening level. A public health goal is not an enforceable standard but represents the level that does not pose a significant health risk.

But in setting a regulatory standard in 2014, California set a much higher bar of 10 ppb after weighing the technical feasibility of detecting the contaminant at low levels and treatment costs.

Jacqueline MacDonald Gibson, who specializes in risk assessment at UNC Gillings School of Global Public Health, said North Carolina's screening level is "extremely, extremely, extremely conservative." Among other assumptions, she said, it makes the leap that humans will develop tumors as rats did.

"It's kind of unfair to ask homeowners to answer what does 1 in a million mean," she said. "If it were just me, it's a judgment call,. But if it were my well and the standard is much below what California says is acceptable, I would go ahead and drink the water."

Whether the level is too conservative, she added, is for policymakers to decide.

Bruce Henderson: 704-358-5051, @bhender

Legislators probe conflicting messages on water drinking-safety standards

By Bruce Henderson
bhenderson@charlotteobserver.com
January 13, 2016 09:29 PM , Updated January 14, 2016 12:01 PM

Legislators probed a question Wednesday that has bedeviled regulators and hundreds of North Carolina households: How can contaminants that are deemed safe in public water systems be labeled risky in private wells?

The state Health Department last spring advised more than 400 well owners, neighbors of Duke Energy power plants, not to drink their water. Most warnings cited detections of two substances that might come from Duke's coal ash ponds.

But similar levels of the contaminants, hexavalent chromium and vanadium, also appear in the municipal water of Charlotte, other North Carolina cities and across the United States. That water is judged safe to drink under federal standards.

"We're telling people that their water is unsafe, and now we're telling them that maybe it might not be," Sen. Andrew Brock, R-Mocksville, said as the Environmental Review Commission met Wednesday. "Nothing gets more personal than messing with somebody's water."

The state's environment and health agencies sparred for months, internal records show, over how to assess contaminants in private wells in the absence of relevant standards.

Officials worried most about hexavalent chromium, a form of the metal that may cause cancer in people who drink tainted water. Hexavalent chromium figured in "Erin Brockovich," the 2000 movie based on real-life groundwater contamination in California.

Research and the understanding of acceptable levels of toxic substances in the environment is evolving.

In 2008, the Environmental Protection Agency began considering whether to set limits on hexavalent chromium. The EPA has called it likely to cause cancer in humans if ingested in drinking water because of tumors found in rats and mice, and because of some evidence of stomach cancers in humans.

But North Carolina, like the federal government, has set no specific limit on how much hexavalent chromium in drinking water is safe. The state instead has a standard for total chromium that includes hexavalent chromium.

In North Carolina, as officials prepared to test nearly 500 wells near Duke's power plants, they needed a benchmark by which to compare results. The Department of Health and

Human Services used its own calculations: the level that might cause one cancer in 1 million people over a lifetime of exposure.

Department of Environmental Quality officials expressed alarm that the newly calculated screening level for hexavalent chromium in wells, 0.07 parts per billion, was too tough. Public water systems have only to meet a far higher federal standard for total chromium of 100 ppb, which includes hexavalent chromium.

Conflicting standards, DEQ argued, would mislead the public.

“Directing people to undertake certain mitigating activities with perhaps negligible health benefit is very different than alerting them to their risk in an understandable way,” Jessica Godreau, chief of the state’s public water supply section, wrote another DEQ official last March.

DEQ eventually consented to the tougher standard. While 424 of 476 well owners got don’t-drink advisories, only 12 wells broke federal water standards.

Nearly a year later, Assistant Environment Secretary Tom Reeder told the commission, “It’s incredibly confusing to the consumer.”

“Decide which agency is in charge,” said Sen. Ronald Rabin, a Harnett County Republican. “It can’t be two different agencies in charge of water or it’s chaos.”

Municipal, private water

Health officials say they followed protocol in developing the screening levels on which their recommendations were based.

“One reason it’s complex is that we have municipal water, groundwater, new wells and old wells. You’ll hear different (standards) for all those things,” said Dr. Randall Williams, deputy secretary of health services. “We’re aware that different agencies and different parts of the government look at each of these four entities in different ways.”

While public systems have to comply with federal standards, private well owners are essentially on their own to ensure their water is safe. The state investigation of Duke’s groundwater contamination followed a 2014 ash spill into the Dan River and state legislation that ordered a broader look at ash issues.

The health agency will reassess its recommendations when more groundwater test data are reported in the next month, he said.

Amy Brown, a neighbor of Duke’s Allen plant in Gaston County, said she appreciated Williams’ personal visit after Christmas. But after eight months on bottled water, she added, her neighborhood is "in limbo. We have no real answer. We can't sell our houses. And we didn't ask for this, not one bit of it."

Duke says groundwater data indicate the well contaminants come from natural sources, not ash ponds.

Similar levels of hexavalent chromium and vanadium occur in soil and rock miles from ash ponds, Duke says. With one exception, it says, the boron that serves as an indicator of ash has not been found in private wells.

"We strongly agree that clarity is needed on state drinking water standards so plant neighbors and others across the state who have been told not to drink their water get this issue resolved soon," spokeswoman Erin Culbert said by email.

'Conservative' standard

Hexavalent chromium is used to make stainless steel and tan leather and to preserve wood. Pacific Gas & Electric, which settled a class-action lawsuit over groundwater contamination in California, used it to reduce corrosion at a power plant.

North Carolina officials, in calculating a screening level for the substance, relied on California's work with hexavalent chromium.

In 2011, California set the nation's first "public health goal" for hexavalent chromium in drinking water: 0.02 ppb, even lower than North Carolina's screening level. A public health goal is not an enforceable standard but represents the level that does not pose a significant health risk.

But in setting a regulatory standard in 2014, California set a much higher bar of 10 ppb after weighing the technical feasibility of detecting the contaminant at low levels and treatment costs.

Jacqueline MacDonald Gibson, who specializes in risk assessment at UNC Gillings School of Global Public Health, said North Carolina's screening level is "extremely, extremely, extremely conservative." Among other assumptions, she said, it makes the leap that humans will develop tumors as rats did.

"It's kind of unfair to ask homeowners to answer what does 1 in a million mean," she said. "If it were just me, it's a judgment call,. But if it were my well and the standard is much below what California says is acceptable, I would go ahead and drink the water."

Whether the level is too conservative, she added, is for policymakers to decide.

Bruce Henderson: 704-358-5051, @bhender

I/A

TOXIC CHEMICAL

University study finds coal ash not source of well contaminant

BY BRUCE HENDERSON
bhenderson@charlotteobserver.com

A contaminant at the center of a monthslong furor over coal ash and polluted wells doesn't come from ash after all, Duke University scientists report in a study published Wednesday.

Hexavalent chromium turns out to be surprisingly widespread in North Carolina's Piedmont, the study says, and occurs naturally.

The toxic form of chromium was detected last year in private wells near Duke Energy's coal-fired power plants and suspected of coming from the ash stored there. Hundreds of well owners were warned not to use their wells, in part because hexavalent chromium in drinking water might cause cancer.

The state's decision to rescind most of those advisories in March prompted bitter exchanges among two state health officials, department leaders and Gov. Pat McCrory's office.

The study published in the journal Environmental Science and Technology Letters may lay

SEE CONTAMINANT, 2A


DAVIE HINSHAW dhinshaw@charlotteobserver.com
A mountain of coal stands next to Duke Energy's Marshall Steam Station on Lake Norman as seen from the coal ash basin in May.

I/A

FROM PAGE 1A

CONTAMINANT

only part of the controversy to rest. Hexavalent chromium in water remains a threat, experts say, no matter the source. About half of North Carolina's 10 million residents rely on wells for drinking water.

Duke, which has insisted that data show its coal ash has not harmed private wells, claimed vindication.

"When combined with previous research, there is overwhelming evidence that coal ash basins are not impacting water quality in neighbor wells," said Harry Sideris, senior vice president of environmental, health and safetyfor the utility. "This study is an extraordinary development, particularly for hundreds of plant neighbors who have been needlessly concerned that ash basins contributed hexavalent chromium or other substances to their wells."

Duke Energy said it will still abide by a state law that requires it to provide alternative water sources to owners of contaminated wells near its plants.

Hexavalent chromium rose to public notice with the 2000 movie "Erin Brockovich," about a real case in which contaminants released by a California utility polluted the groundwater under a small town.

Industrial releases were long thought to be a major source of hexavalent chromium in the environment. But that's beginning to change. The American Water Works Association, which represents water utilities, says chromium in geologic formations is the major source in drinking water.

The Duke University study found that hexavalent chromium leaches from volcanic rock into groundwater under much of North Carolina's Piedmont. Because similar formations are found across the Southeast, said lead author Avner Vengosh, millions of people outside North Carolina could be at risk.

The researchers collected water from 376 wells both near and far from coal ash ponds. Hexavalent chromium was found in about 90 percent of the wells, some at levels considered unsafe in drinking water.

Then they used tracers developed by Vengosh's team to identify geochemical "fingerprints" that can trace contaminants to their source.

Contaminants leaking from coal ash present a distinct geochemical profile of elements such as boron, strontium and arsenic, Vengosh said. When his team found water with hexavalent chromium in it, he said, "we see a totally different chemistry."

Finding high levels of the contaminant over a large area, regardless of how close to ash ponds, supports the conclusion that ash isn't the source, he said.

The findings don't mean ash ponds are benign, Vengosh said. Previous research has found other contaminants including arsenic, a carcinogen, and selenium leaking from them.

NATURAL SOURCES

North Carolina's Department of Environmental Quality has not explicitly stated whether the hexavalent chromium detected near Duke Energy's power plants came from natural sources but offered hints last year.

DEQ tested 24 private wells that are near Duke's plants but too far away to be affected by its ash ponds. Elevated levels of hexavalent chromium were found in 12 of the wells, and the agency recommended that seven others be retested for the chemical. Duke tested about 200 of its employees' wells with similar results.

Duke Energy said the "clear evidence" from multiple sources shows that "it's time to move forward with safely closing ash basins in ways that protect people, the environment and wallets."

Vengosh said the research also points to the need for states to set water safety standards for hexavalent chromium. Only California, where it also occurs naturally, has a state standard.

Arsenic, which is found in ash, also occurs naturally in the Carolina Slate Belt, a geologic formation that arcs across the Piedmont. North Carolina has a groundwater standard for arsenic but includes hexavalent chromium in the standard for total chromium.

"From a public health standpoint, it doesn't matter whether it's naturally occurring or from a man-made source. The toxicity risk is the same and the cancer risk is the same," state toxicologist Kenneth Rudo said of the two contaminants.

The federal water standard for chromium also includes its hexavalent form, but the Environmental Protection Agency is reviewing health studies to decide whether hexavalent chromium merits a separate standard.

North Carolina's DEQ said it will adopt new or revised water standards when the federal government does.

Bruce Henderson: 704-358-5051, @bhender

Coal ash not the source of well contaminant, Duke University study finds

By Bruce Henderson
bhenderson@charlotteobserver.com

October 26, 2016 08:00 AM , Updated October 26, 2016 07:21 PM

A contaminant at the center of a months-long furor over coal ash and polluted wells doesn't come from ash after all, Duke University scientists report in a study published Wednesday.

Hexavalent chromium turns out to be surprisingly widespread in North Carolina's Piedmont, the study says, and occurs naturally.

The toxic form of chromium was detected last year in private wells near Duke Energy's coal-fired power plants and suspected of coming from the ash stored there. Hundreds of well owners were warned not to use their wells, in part because hexavalent chromium in drinking water might cause cancer.

The state's decision to rescind most of those advisories in March prompted bitter exchanges among two state health officials, department leaders and Gov. Pat McCrory's office.

The study published in the journal Environmental Science and Technology Letters may lay only part of the controversy to rest. Hexavalent chromium in water remains a threat, experts say, no matter the source. About half of North Carolina's 10 million residents rely on wells for drinking water.

Duke Energy, which has insisted that data shows its coal ash has not harmed private wells, claimed vindication.

"When combined with previous research, there is overwhelming evidence that coal ash basins are not impacting water quality in neighbor wells," said Harry Sideris, senior vice president of environmental, health and safety. "This study is an extraordinary development, particularly for hundreds of plant neighbors who have been needlessly concerned that ash basins contributed hexavalent chromium or other substances to their wells."

Duke said it will still abide by a state law that requires it to provide alternative water sources to owners of contaminated wells near its plants.

Hexavalent chromium rose to public notice with the 2000 movie "Erin Brockovich," a dramatization of a real case in which contaminants released by a California utility polluted the groundwater under a small town.

Industrial releases were long thought to be a major source of hexavalent chromium in the environment. But that's beginning to change. The American Water Works Association, which represents water utilities, says chromium in geologic formations is the major source in drinking water.

The Duke study found that hexavalent chromium leaches from volcanic rock into groundwater under much of North Carolina's Piedmont. Because similar formations are found across the Southeast, said lead author Avner Vengosh, millions of people outside North Carolina could be at risk without knowing it.

The researchers collected water from 376 wells both near and far from coal ash ponds. Hexavalent chromium was found in about 90 percent of the wells, some at levels considered unsafe in drinking water.

Then they used tracers developed by Vengosh's team to identify geochemical "fingerprints" that can trace contaminants to their source.

Contaminants leaking from coal ash present a distinct geochemical profile of elements such as boron, strontium and arsenic, Vengosh said. When his team found water with hexavalent chromium in it, he said, "we see a totally different chemistry."

Finding high levels of the contaminant over a large area, regardless of how close to ash ponds, supports the conclusion that ash isn't the source, he said.

The findings don't mean ash ponds are benign, Vengosh said. Previous research has found other contaminants including arsenic, a carcinogen, and selenium leaking from them.

Natural sources

North Carolina's Department of Environmental Quality has not explicitly stated whether the hexavalent chromium detected near Duke's power plants came from natural sources, but offered hints last year.

DEQ tested 24 private wells that are near Duke's plants but too far away to be affected by its ash ponds. Elevated levels of hexavalent chromium were found in 12 of the wells, and the agency recommended that seven others be retested for the chemical. Duke Energy tested about 200 of its employees' wells with similar results.

Duke Energy said the "clear evidence" from multiple sources shows that "it's time to move forward with safely closing ash basins in ways that protect people, the environment and wallets."

Vengosh said the research also points to the need for states to set water safety standards for hexavalent chromium. Only California, where it also occurs naturally, has a state standard.

Arsenic, which is found in ash, also occurs naturally in the Carolina Slate Belt, a geologic formation that arcs across the Piedmont. North Carolina has a groundwater standard for arsenic but includes hexavalent chromium in the standard for total chromium.

“From a public health standpoint, it doesn’t matter whether it’s naturally occurring or from a man-made source. The toxicity risk is the same and the cancer risk is the same,” state toxicologist Kenneth Rudo said of the two contaminants.

The federal water standard for chromium also includes its hexavalent form, but the Environmental Protection Agency is reviewing health studies to decide whether hexavalent chromium merits a separate standard.

North Carolina’s DEQ said it will adopt new or revised water standards when the federal government does. The department said it will continue groundwater tests to establish concentrations of hexavalent chromium that represent natural conditions.

Bruce Henderson: 704-358-5051, @bhender

I/A

Hart Exhibit 28
Docket No. E-7, Sub 1214

From: Jimmie A Stowe Jr <JAStowe@dukeenergy.com>
Sent: Friday, August 13, 2004 9:53 AM
To: Ruhe, Mike; Mathis, Tony R; Ervine, Tim; Burrell, Donna L; Mark S Hays; Everett, George T; Leap, Tom Y Jr; Starcher, Michael S; Newell, Jeff W; Larry S Harper
Cc: Miller, William M; Scruggs, Don
Subject: Groundwater Well Installation at Allen Steam Station

Bill Miller, Don Scruggs and Allen Stowe met with Bill Goforth of the NC DENR DWQ Groundwater Section on August 12, 2004 to discuss the placement and installation of monitoring wells around the Allen ash basin. Allen Stowe explained the 2000 Bevill Determination and ongoing discussions with the utility industry and EPA regarding groundwater monitoring for unlined surface impoundments. Allen Stowe also stated Duke Power's intent to be proactive on this issue and to initiate groundwater monitoring at its unlined surface impoundments before any agreement between the utility industry and EPA was accepted. Mr. Goforth was informed that monitoring wells would be installed at Allen and Marshall Steam Station(s) this year. The other seven NC fossil sites would have monitoring wells installed in 2005-2006.

After a brief review of site maps by Bill Miller and Don Scruggs, a tour of the ash basin and the surrounding areas was given. Mr. Goforth stated that the pre-existing wells on the dike adjacent to the Catawba River could investigated for use (with minor modifications). Mr. Goforth concurred with the location and the proposed depths (well pair - one shallow, one deep) for the background and the two monitoring wells located closest to locations where the ash basin is located near residences. Mr Goforth requested that two additional monitoring wells be sited between the western side of the ash basin and the housing development. NC DENR and Gaston County officals will be contacted to ascertain additional permit requirements. A modification to the existing NPDES permit may also be necessitiated. These wells will be installed the week of September 20, 2004. Hopefully, the groundwater monitoring wells at MSS will also be installed during this week.

Overall, the meeting atmosphere was very cordial and productive. If additional information is required, please contact me.
Thanks

Allen Stowe
phone: (704) 382-4309
fax: (704) 382-9840
e-mail: jastow@duke-energy.com

32214 **Federal Register** / Vol. 65, No. 99 / Monday, May 22, 2000 / Rules and Regulations

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 261

[FRL–6588–1]

RIN 2050–AD91

Notice of Regulatory Determination on Wastes From the Combustion of Fossil Fuels

AGENCY: Environmental Protection Agency.

ACTION: Regulatory determination.

SUMMARY: This document explains EPA's determination of whether regulation of fossil fuel combustion wastes is warranted under subtitle C of the Resource Conservation and Recovery Act (RCRA). Today's action applies to all remaining fossil fuel combustion wastes other than high volume coal combustion wastes generated at electric utilities and independent power producing facilities and managed separately, which were addressed by a 1993 regulatory determination. These include: Large-volume coal combustion wastes generated at electric utility and independent power producing facilities that are co-managed together with certain other coal combustion wastes; coal combustion wastes generated by non-utilities; coal combustion wastes generated at facilities with fluidized bed combustion technology; petroleum coke combustion wastes; wastes from the combustion of mixtures of coal and other fuels (*i.e.*, co-burning); wastes from the combustion of oil; and wastes from the combustion of natural gas.

The Agency has concluded these wastes do not warrant regulation under subtitle C of RCRA and is retaining the hazardous waste exemption under RCRA section 3001(b)(3)(C). However, EPA has also determined national regulations under subtitle D of RCRA are warranted for coal combustion wastes when they are disposed in landfills or surface impoundments, and that regulations under subtitle D of RCRA (and/or possibly modifications to existing regulations established under authority of the Surface Mining Control and Reclamation Act (SMCRA)) are warranted when these wastes are used to fill surface or underground mines.

So that coal combustion wastes are consistently regulated across all waste management scenarios, the Agency also intends to make these national regulations for disposal in surface impoundments and landfills and minefilling applicable to coal combustion wastes generated at electric utility and independent power producing facilities that are not co-managed with low volume wastes,.

The Agency has concluded that no additional regulations are warranted for coal combustion wastes that are used beneficially (other than for minefilling) and for oil and gas combustion wastes. We do not wish to place any unnecessary barriers on the beneficial use of fossil fuel combustion wastes so that they can be used in applications that conserve natural resources and reduce disposal costs. Currently, about one-quarter of all coal combustion wastes are diverted to beneficial uses. We support increases in these beneficial uses, such as for additions to cement and concrete products, waste stabilization and use in construction products such as wallboard.

DATES: Comments in response to data and information requests in this document are due to EPA on September 19, 2000.

ADDRESSES: Public comments and supporting materials are available for viewing in the RCRA Information Center (RIC). In addition to the data and information that was included in the docket to support the RTC on FFC waste and the Technical Background Documents, the docket also includes the following document: Responses to Public Comments on the Report To Congress, Wastes from the Combustion of Fossil Fuels. The RIC is located at Crystal Gateway I, First Floor, 1235 Jefferson Davis Highway, Arlington, VA. The Docket Identification Number is F–2000–FF2F–FFFFF. The RIC is open from 9 a.m. to 4 p.m., Monday through Friday, excluding federal holidays. To review docket materials, we recommend that the public make an appointment by calling 703 603–9230. The public may copy a maximum of 100 pages from any regulatory docket at no charge. Additional copies cost $0.15/page. The index and some supporting materials are available electronically. See the **SUPPLEMENTARY INFORMATION** section for information on accessing them.

Commenters must send an original and two copies of their comments referencing docket number F–2000–FF2F–FFFFF to: (1) If using regular US Postal Service mail: RCRA Docket Information Center, Office of Solid Waste (5305G), U.S. Environmental Protection Agency Headquarters (EPA, HQ), Ariel Rios Building, 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0002; or (2) if using special delivery, such as overnight express service: RCRA Docket Information Center (RIC), Crystal Gateway One, 1235 Jefferson Davis Highway, First Floor, Arlington, VA 22202. Comments may also be submitted electronically through the Internet to: *rcra-docket@epa.gov.* Comments in electronic format should also be identified by the docket number F–2000–FF2F–FFFFF and must be submitted as an ASCII file avoiding the use of special characters and any form of encryption.

Commenters should not submit electronically any confidential business information (CBI). An original and two copies of CBI must be submitted under separate cover to: RCRA CBI Document Control Officer, Office of Solid Waste (5305W), U.S. EPA, Ariel Rios Building, 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0002.

FOR FURTHER INFORMATION CONTACT: For general information, contact the RCRA Hotline at 800 424–9346 or TDD 800 553–7672 (hearing impaired). In the Washington, DC, metropolitan area, call 703 412–9810 or TDD 703 412–3323.

For more detailed information on specific aspects of this regulatory determination, contact Dennis Ruddy, Office of Solid Waste (5306W), U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, NW, Washington, DC 20460–0002, telephone (703) 308–8430, e-mail address *ruddy.dennis@epa.gov.*

SUPPLEMENTARY INFORMATION: The index and several of the primary supporting materials are available on the Internet. You can find these materials at *<http://www.epa.gov/epaoswer/other/fossil/index.htm.*

The official record for this action will be kept in paper form. Accordingly, EPA will transfer all comments received electronically into paper form and place them in the official record, which will also include all comments submitted directly in writing. The official record is the paper record maintained at the address in **ADDRESSES** at the beginning of this notice.

EPA will not immediately reply to commenters electronically other than to seek clarification of electronic comments that may be garbled in transmission or during conversion to paper form, as discussed above.

The contents of today's notice are listed in the following outline:

1. General Information

A. What Action Is EPA Taking Today?

In today's action, we are determining that regulation of fossil fuel combustion (FFC) wastes under subtitle C of the Resource Conservation and Recovery Act (RCRA) is not warranted. This determination covers the following wastes:

- Large-volume coal combustion wastes generated at electric utility and independent power producing facilities that are co-managed together with certain other coal combustion wastes;
- Coal combustion wastes generated at non-utilities;
- Coal combustion wastes generated at facilities with fluidized bed combustion technology;
- Petroleum coke combustion wastes;
- Wastes from the combustion of mixtures of coal and other fuels (i.e., co-burning of coal with other fuels where coal is at least 50% of the total fuel);
- Wastes from the combustion of oil; and
- Wastes from the combustion of natural gas.

While these wastes remain exempt from subtitle C, we have further decided to establish national regulations under subtitle D of RCRA (RCRA sections 1008(a) and 4004(a)) for coal combustion wastes that are disposed in landfills or surface impoundments or used to fill surface or underground mines. For coal combustion wastes used as minefill, we will consult with the Office of Surface Mining in the Department of the Interior and thoroughly assess whether equivalent protectiveness could be achieved by using regulatory authorities available under the Surface Mining Control and Reclamation Act (SMCRA), as well as those afforded under the Resource Conservation and Recovery Act. We will consider whether RCRA subtitle D or SMCRA authorities or some combination of both are most appropriate to regulate the disposal of coal combustion wastes when used for minefill in surface and underground mines to ensure protection of human health and the environment. These standards will be developed through notice and comment rulemaking and in consultation with states and other stakeholders. These regulations will, in EPA's view, ensure that the trend towards improved management of coal combustion wastes over recent years will accelerate and will ensure a consistent level of protection of human health and the environment is put in place across the United States.

If, as a result of comments in response to this notice; the forthcoming analyses identified in this notice; or additional information garnered in the course of developing these national regulations; we find that there is a need for regulation under the authority of RCRA subtitle C, the Agency will revise this determination accordingly.

We recognize our decision to develop regulations under RCRA subtitle D (or, for minefilling, possibly under SMCRA) for the above-listed coal combustion wastes was not specifically identified as an option in our March 31, 1999 Report to Congress. Our final determination reflects our consideration of public comments received on the Report to Congress and other analyses that we conducted.

Today's decision was, in the Agency's view, a difficult one, given the many competing considerations discussed throughout today's notice. After considering all of the factors specified in RCRA section 8002(n), we have decided as discussed further below, that the decisive factors are the trends in present disposal and utilization practices (section 8002 (n)(2)), the current and potential utilization of the wastes (Section 8002 (n)(8), and the admonition against duplication of efforts by other federal and state agencies.

As described in the Report to Congress, the utility industry has made significant improvements in its waste management practices over recent years, and most state regulatory programs are similarly improving. For example, in the utility industry the use of liners and groundwater monitoring at landfills and surface impoundments has increased substantially over the past 15 years as indicated in the following table.

PERCENT OF UTILITY COAL COMBUSTION WASTE MANAGEMENT UNITS WITH CONTROLS IN 1995

Waste management unit	Liners		Groundwater monitoring	
	Percent of all units	Percent of new units *	Percent of all units	Percent of new units *
Landfills	57	75	85	88
Surface Impoundments	26	60	38	65

* New units constructed between 1985–1995.
Source: USWAG, EPRI 1995.

Public comments and other analyses, however, have convinced us that these wastes could pose risks to human health and the environment if not properly managed, and there is sufficient evidence that adequate controls may not be in place—for example, while most states can now require newer units to include liners and groundwater monitoring, 62% of existing utility surface impoundments do not have groundwater monitoring. This, in our view, justifies the development of national regulations. We note, however, that some waste management units may not warrant liners and/or groundwater monitoring, depending on site-specific characteristics.

New information we received in public comments includes additional documented damage cases, as well as cases indicating at least a potential for damage to human health and the environment. We did not independently investigate these damage cases; rather, we relied on information contained in state files. While the absolute number of documented damage cases is not large, we have considered the evidence of proven and potential damage in light of the proportion of facilities that lack basic environmental controls (*e.g.,* groundwater monitoring). We acknowledge, moreover, that our inquiry into the existence of damage cases was focused primarily on a subset of states—albeit states that account for almost 20 percent of coal fired utility electricity generation capacity. Given the volume of coal combustion wastes generated nationwide (115 million tons) and the numbers of facilities that currently lack some basic environmental controls, especially groundwater monitoring, other cases of proven and potential damage are likely to exist. Because EPA did not use a statistical sampling methodology to evaluate the potential for damage, the Agency is unable to determine whether the identified cases are representative of the conditions at all facilities and, therefore, cannot quantify the extent and magnitude of damages at the national level.

Since the Report to Congress, we have conducted additional analyses of the potential for the constituents of coal combustion wastes to leach in dangerous levels into ground water. Based on a comparison of drinking water and other appropriate standards to leach test data from coal combustion waste samples, we identified a potential for risks from arsenic that we cannot dismiss at this time. This conclusion is based on possible exceedences of a range of values that EPA is currently considering for a revised arsenic MCL. Once a new arsenic MCL is established, additional groundwater modeling may be required to evaluate the likelihood of exceeding that MCL.

As discussed further below, in light of certain comments received on the Report to Congress, we are not relying on a quantitative groundwater risk assessment to assess potential risks to human health or the environment. In the absence of a more complete groundwater risk assessment, we are unable at this time to draw quantitative conclusions regarding the risks due to arsenic or other contaminants posed by improper waste management. Once we have completed a review of our groundwater model and made any necessary changes, we will reevaluate groundwater risks and take appropriate regulatory actions. We will specifically assess new modeling results as they relate to any promulgated changes in the arsenic MCL.

We acknowledge that, even without federal regulatory action, many facilities in the utility industry have either voluntarily instituted adequate environmental controls or have done so at the direction of states that regulate these facilities. In addition, we found that for the proven damage cases, the states (and in two cases, EPA under the Superfund program) have taken action to mitigate risk and require corrective action. However, in light of the evidence of actual and potential environmental releases of metals from these wastes; the large volume of wastes generated from coal combustion; the proportion of existing and even newer units that do not currently have basic controls in place; and the presence of hazardous constituents in these wastes; we believe, on balance, that the best means of ensuring that adequate controls are imposed where needed is to develop national subtitle D regulations. As we develop and issue the national regulations, we will try to minimize disruptions to operation of existing waste management units.

In taking today's action, we carefully considered whether to develop national regulations under RCRA subtitle D or subtitle C authorities. One approach we considered was to promulgate regulations pursuant to subtitle C authority, similar to recently proposed regulations applicable to cement kiln dust. Under this approach, EPA would have established national management standards for coal combustion wastes managed in landfills and surface impoundments and used for minefilling, as well as a set of tailored subtitle C requirements, promulgated pursuant to RCRA section 3004(x). If wastes were properly managed in accordance with subtitle D-like standards, they would not be classified as a hazardous waste. If wastes were not properly managed, they would become listed hazardous wastes subject to tailored subtitle C standards. This approach would give EPA enforcement authority in states following their adoption of the contingent management listing.

We believe, however, for the reasons described below, the better approach at this time to ensuring adequate management of FFC wastes is to develop national regulations under subtitle D rather than subtitle C. EPA has reached this conclusion in large part based on consideration of ''present disposal and utilization practices.'' RCRA § 8002(n). As noted above, present disposal practices in landfills and surface impoundments are significantly better than they have been in the past in terms of imposing basic environmental controls such as liners and groundwater monitoring. This trend is the result of increasing regulatory oversight by states of the management of these wastes as well as voluntary industry improvements. In the 1980's, only 11 states had authority to require facilities to install liners, and 28 states had the authority to require facilities to conduct groundwater monitoring at landfills. As of 1995, these rates were significantly higher, with 43 states having the authority to require liners and 46 states having the authority to require groundwater monitoring at landfills. When authority under state groundwater and drinking water regulations are considered, some commenters have suggested that nearly all states can address the management of these wastes. Thus, with the exception of relatively few states, the regulatory infrastructure is generally in place at the state level to ensure adequate management of these wastes.

While the trend both in terms of state regulatory authorities and the imposition of controls at these facilities has been positive, between 40 and 70 percent of sites lacked controls such as liners and/or groundwater monitoring as of 1995. This gap is of environmental concern given the potential for risks posed by mismanagement of coal combustion wastes in certain circumstances. Nonetheless, given most of the states' current regulatory capabilities and the evidence that basic controls are increasingly being put in place by the states and facilities (see RCRA section 8002(n), which directs EPA to consider actions of state and other federal agencies with a view to avoiding duplication of effort), EPA believes that subtitle D controls will provide sufficient clarity and incentive for states to close the remaining gaps in coverage, and for facilities to ensure that their wastes are managed properly.

For minefilling, although we have considerable concern about certain current practices (*e.g.,* placement directly into groundwater) we have not yet identified a case where placement of coal wastes can be determined to have actually caused increased damage to ground water. In addition, there is a federal regulatory program—SMCRA—expressly designed to address environmental risks associated with coal mines. Finally, given that states have been diligent in expanding and upgrading programs, as they have done for surface impoundments and landfills, we believe they will be similarly responsive in addressing environmental concerns arising from this emerging practice. In short, we arrive at the same conclusions, for substantially the same reasons, for this practice as we did for landfills and surface impoundments: that subtitle D controls, or upgraded SMCRA controls or a combination of the two, should provide sufficient clarity and incentive to ensure proper handling of this waste. Having determined that subtitle C regulation is not warranted for all other management practices, EPA does not see a basis in the record for carving this one practice out for separate regulatory treatment.

Once these regulations are effective, facilities would be subject to citizen suits for any violation of the standards. If EPA were addressing wastes that had not been addressed by the states (or the federal government) in the past, or an industry with wide evidence of irresponsible solid waste management practices, EPA may well conclude that the additional incentives for improvement and compliance provided by the subtitle C scheme—the threat of federal enforcement and the stigma associated with improper management of RCRA subtitle C waste—were necessary. But the record before us indicates that the structure and the sanctions associated with a subtitle D approach (or a SMCRA approach if EPA determines it is equivalent) should be sufficient.

We also see a potential downside to pursuing a subtitle C approach. Section 8002(n)(8) directs us to consider, among other factors, "the current and potential utilization of such materials." Industry commenters have indicated that they believe subjecting any coal combustion wastes to a subtitle C regime would place a significant stigma on these wastes, the most important effect being that it would adversely impact beneficial reuse. As we understand it, the concern is that, even though beneficially reused waste would not be hazardous under the contemplated subtitle C approach, the link to subtitle C would nonetheless tend to discourage purchase and re-use of the waste. We do not wish to place any unnecessary barriers on the beneficial uses of these wastes, because they conserve natural resources, reduce disposal costs and reduce the total amount of waste destined for disposal. States and industry have also expressed concern that regulation under subtitle C could cause a halt in the use of coal combustion wastes to reclaim abandoned and active mine sites. We recognize that when done properly, minefilling can lead to substantial environmental benefits. EPA believes the contingent management scheme we discussed should diminish any stigma that might be associated with the subtitle C link. Nonetheless, we acknowledge the possibility that the approach could have unintended consequences. We would be particularly concerned about any adverse effect on the beneficial re-use market for these wastes because more than 23 percent (approximately 28 million tons) of the total coal combustion waste generated each year is beneficially reused and an additional eight percent (nine million tons) is used for minefilling. EPA believes that such reuse when performed properly, is by far the environmentally preferable destination for these wastes, including when minefilled. Normally, concerns about stigma are not a deciding factor in EPA's decisions under RCRA, given the central concern under the statute for protection of human health and the environment. However, given our conclusion that the subtitle D approach here should be fully effective in protecting human health and the environment, and given the large and salutary role that beneficial reuse plays for this waste, concern over stigma is a factor supporting our decision today that subtitle C regulation is unwarranted in light of our decision to pursue a subtitle D approach.

Additionally, in a 1993 regulatory determination, EPA previously addressed large volume coal combustion wastes generated at electric utility and independent power producing facilities that manage the wastes separately from certain other low volume and uniquely associated coal combustion wastes (see 58 FR 42466; August 9, 1993). Our 1993 regulatory determination maintained the exemption of these large volume coal combustion wastes from being regulated as hazardous wastes when managed separately from other wastes (e.g., in monofills). We intend that the national subtitle D regulations we develop for the coal combustion wastes subject to today's regulatory determination will also be applicable to the wastes covered in the 1993 regulatory determination for the reasons listed below, so that all coal combustion wastes are consistently regulated for placement in landfills, surface impoundments, and minefills.

- The co-managed coal combustion wastes that we studied extensively in making today's regulatory determination derive their characteristics largely from these large-volume wastes and not from the other wastes that are co-managed with them.
- We believe that the risks posed by the co-managed coal combustion wastes result principally from the large-volume wastes.
- These large-volume coal combustion wastes, account for over 20% of coal combustion wastes.

As we proceed with regulation development, we will also take enforcement action under RCRA section 7003 when we identify cases of imminent and substantial endangerment. We will also use Superfund remedial and emergency response authorities under the Comprehensive Environmental Response Compensation and Liabilities Act (CERCLA), as appropriate, to address damages that result in risk to human health and the environment.

However, as stated above, this decision was a difficult one and EPA believes that, absent our conclusions regarding the current trends in management of this waste, the waste might present sufficient potential threat to human health and the environment to justify subtitle C regulation. There are several factors that might cause us to rethink our current determination. First, and perhaps most importantly, if current trends toward protective management do not continue, EPA may well determine that subtitle C regulation is warranted for this waste. As we have stated, we do not believe the current gaps in the basic controls are acceptable, and our determination that subtitle C regulation is not warranted is premised to a large extent on our conclusion that subtitle D regulation will be sufficient to close these gaps. If this conclusion turns out not to be warranted, we would be inclined to re-examine our current decision.

Second, EPA will continue to examine available information and, as a result of the ongoing review, may conclude over the next several months that this decision should be revised. Our ongoing review will include consideration of: (1) The extent to which fossil fuel combustion wastes have caused actual or potential damage to human health or the environment; (2) the environmental effects of filling underground and surface coal mines with fossil fuel combustion wastes; and (3) the adequacy of existing state and/or federal regulation of these wastes. Finally, the agency will consider the results of a report of the National Academy of Sciences regarding the adverse human health effects of mercury, one of the constituents in fossil fuel combustion wastes. EPA believes that this report will enhance our understanding of the risks due to exposure to mercury. All of these efforts may result in a subsequent revision of today's regulatory determination.

Finally, relating to oil combustion wastes, we will work with relevant stakeholders so that any necessary measures are taken to ensure that oil combustion wastes currently managed in the two known remaining unlined surface impoundments are managed in a manner that protects human health and the environment.

B. What Is the Statutory Authority for This Action?

We are issuing today's notice under the authority of RCRA section 3001 (b) (3) (C), as amended. This section exempts certain wastes, including fossil fuel combustion wastes, from hazardous waste regulation until the Agency completes a Report to Congress mandated by RCRA section 8002 (n) and maintains the exemption, unless the EPA Administrator makes a determination that subtitle C (hazardous waste) regulation is warranted. RCRA section 3004 (x) provides the Agency with flexibility in developing subtitle C standards. If appropriate, these formerly exempted wastes may not be subjected to full subtitle C requirements in areas such as treatment standards, liner design requirements and corrective action.

C. What Was the Process EPA Used in Making Today's Decision?

1. What Approach Did EPA Take to Studying Fossil Fuel Combustion Wastes?

We conducted our study of wastes generated by the combustion of fossil fuels in two phases. The first phase, called the Part 1 determination, covered high volume coal combustion wastes (*e.g.,* bottom ash and fly ash) generated at electric utility and independent power producing facilities (non-utility electric power producers that are not engaged in any other industrial activity) and managed separately from other fossil fuel combustion wastes. In 1993, EPA issued a regulatory determination that exempted Part 1 wastes from regulation as hazardous wastes (see 58 FR 42466; August 9, 1993). Today's regulatory determination is the second phase of our effort, or the Part 2 determination. It covers all other fossil fuel combustion wastes not covered in Part 1. This includes high volume, utility-generated coal combustion wastes when co-managed with certain low volume wastes that are also generated by utility coal burners; coal combustion wastes generated by industrial, non-utility, facilities; and wastes from the combustion of oil and gas. Under court order, we are required to complete the Part 2 regulatory determination by April 25, 2000. [1]

[1] The consent decree entered into by EPA (*Frank Gearhart, et al.* v. *Browner, et al.,* No. 91–2435 (D.D.C.) for completing the studies and regulatory determination for fossil fuel combustion wastes used the term "remaining wastes" to differentiate the wastes to be covered in today's decision from the large-volume utility coal combustion wastes that were covered in the August 1993 regulatory determination (see 58 FR 42466).

2. What Statutory Requirements Does EPA Have To Meet in Making Today's Regulatory Determinations?

RCRA section 8002(n) specifies eight study factors that we must take into account in our decision-making. These are:

1. The source and volumes of such materials generated per year.
2. Present disposal practices.
3. Potential danger, if any, to human health and the environment from the disposal of such materials.
4. Documented cases in which danger to human health or the environment has been proved.
5. Alternatives to current disposal methods.
6. The costs of such alternatives.
7. The impact of those alternatives on the use of natural resources.
8. The current and potential utilization of such materials.

Additionally, in developing the Report to Congress, we are directed to consider studies and other actions of other federal and State agencies with a view toward avoiding duplication of effort (RCRA section 8002(n)). In addition to considering the information contained in the Report, EPA is required to base its regulatory determination on information received in public hearings and comments submitted on the Report to Congress (RCRA section 3001(b)(3)(C)).

3. What Were the Agency's Sources of Information and Data That Serve as the Basis for This Decision?

We gathered publicly available information from a broad range of sources, including federal and state agencies, industry trade groups, environmental organizations, and open literature searches. We requested information from all stakeholder groups on each of the study factors Congress requires us to evaluate. For many of the study factors, very limited information existed prior to this study. We worked closely with the Edison Electric Institute (EEI), Utility Solid Waste Activities Group (USWAG), the Electric Power Research Institute (EPRI), and the Council of Industrial Boiler Owners (CIBO) as those organizations developed new information. Because other ongoing EPA projects currently focus on portions of the FFC waste generator universe, we also leveraged data collection efforts conducted for air, industrial waste, and hazardous waste programs. In addition, we obtained information from environmental organizations regarding beneficial uses of some FFC wastes and methods for characterizing the risks associated with FFC wastes.

Specifically, we gathered and analyzed the following information from industry, states and environmental groups:

- Published and unpublished materials obtained from state and federal agencies, utilities and trade industry groups, and other knowledgeable parties on the volumes and characteristics of coal, oil, and natural gas combustion wastes and the corresponding low-volume and uniquely associated wastes (see the following section for a description of ''uniquely associated wastes'').
- Published and unpublished materials on waste management practices (including co-disposal and re-use) associated with FFC wastes and the corresponding low-volume and uniquely associated wastes.
- Published and unpublished materials on the potential environmental impacts associated with FFC wastes.
- Published and unpublished materials on trends in utility plant operations that may affect waste volumes and characteristics. We gathered specific information on innovations in scrubber use and the potential impacts of the 1990 Clean Air Act Amendments on waste volumes and characteristics.
- Energy Information Agency (EIA), Department of Energy, data on utility operations and waste generation obtained from EIA's Form 767 database. These data are submitted to EIA annually by electric utilities.
- Site visit reports and accompanying facility submittals for utility and non-utility plants we visited during the study.
- Materials obtained from public files maintained by State regulatory agencies. These materials focus on waste characterization, waste management, and environmental monitoring data, along with supporting background information.

We visited five states to gather specific information about state regulatory programs, FFC waste generators, waste management practices and candidate damage cases related to fossil fuel combustion. The five states we examined in great detail were: Indiana, Pennsylvania, North Carolina, Wisconsin, and Virginia. These five states account for almost 20 percent of coal-fired utility electrical generation capacity.

We also performed a variety of analyses, including human health and ecological risk assessments, analyses of existing federal and state regulatory programs, and economic impact analyses. We discussed and shared these results with all of our stakeholders. We also conducted an external peer review of our risk analysis.

4. What Process Did EPA Follow To Obtain Comments on the Report to Congress?

RCRA requires that we publish a Report to Congress (RTC) evaluating the above criteria. Further, within six months of submitting the report, we must, after public hearings and opportunity for comment, decide whether to retain the exemption from hazardous waste requirements or whether regulation as hazardous waste is warranted. On March 31, 1999, we issued the required RTC on those fossil fuel combustion wastes (coal, oil and gas) not covered in the Part 1 regulatory determination, which are also known as the ''remaining wastes'' (see footnote 1).

We asked the public to comment on the Report and the appropriateness of regulating fossil fuel wastes under subtitle C of RCRA. To ensure that all interested parties had an opportunity to present their views, we held a public meeting with stakeholders on May 21, 1999. The April 28, 1999 **Federal Register** notice provided a 45-day public comment period, until June 14, 1999. We received over 150 requests to extend the public comment period by up to six months. However, we were obligated by a court-ordered deadline to issue our official Regulatory Determination by October 1, 1999. (See 64 FR 31170; June 10, 1999.) In response to requests for an extension, we entered into discussions with the parties to consider an extension of the comment period to ensure that all interested members of the public had sufficient time to complete their review and submit comments. Subsequently, the plaintiffs in *Gearhart* v. *Reilly* moved to modify the consent decree to reopen the comment period and to allow EPA until March 10, 2000 to complete the Regulatory Determination. We supported the motion, and on September 2, 1999, the Court granted the motion. In compliance with the court order, on September 20, 1999, we announced that public comments would be accepted through September 24, 1999 (64 FR 50788; Sept. 20, 1999). We have since received two extensions to the date for the final determination. Currently, EPA is directed to issue the Part 2 regulatory determination by April 25, 2000.

We received about 220 comments on the RTC from the public hearing and our **Federal Register** requests for comments. The docket for this action (Docket No. F–99–FF2P–FFFFF) contains all individual comments presented in the public meetings and hearing, and a transcript from the public hearing, and all written comments. The docket is available for public inspection. Today's decision is based on the RTC, its underlying data and analyses, public comments, and EPA analyses of these comments.

The comments covered a wide variety of topics discussed in the Report to Congress, such as fossil fuel combustion waste generation and characteristics; current and alternative practices for managing FFC waste; documented damage cases and potential danger to human health and the environment; existing regulatory controls on FFC waste management; cost and economic impacts of alternatives to current management practices; FFC beneficial use practices; and our review of applicable state and federal regulations.

D. What Is the Significance of ''Uniquely Associated Wastes'' and What Wastes Does EPA Consider To Be ''Uniquely Associated Wastes?'

Facilities that burn fossil fuels generate combustion wastes and also generate other wastes from processes that are related to the main fuel combustion processes. Often, as a general practice, facilities co-dispose these wastes with the large volume wastes that are subject to the RCRA section 3001 (b) (3) (C) exemption. Examples of these related wastes are:

- Precipitation runoff from the coal storage piles at the facility.
- Waste coal or coal mill rejects that are not of sufficient quality to burn as fuel.
- Wastes from cleaning the boilers used to generate steam.

There are numerous wastes like these, collectively known as ''low-volume'' wastes. Further, when one of these low-volume wastes, during the course of generation or normal handling at the facility, comes into contact with either fossil fuel (*e.g.,* coal, oil) or fossil fuel combustion waste (*e.g.,* coal ash or oil ash) and it takes on at least some of the characteristics of the fuel or combustion waste, we call it a ''uniquely associated'' waste. When uniquely associated wastes are co-managed with fossil fuel combustion wastes, they fall within the coverage of today's regulatory determination. When managed separately, uniquely associated wastes are subject to regulation as hazardous waste if they are listed wastes or exhibit the characteristic of a hazardous waste (see 40 CFR 261.20 and 261.30, which specify when a solid waste is considered to be a hazardous waste).

The Agency recognizes that determining whether a particular waste is uniquely associated with fossil fuel combustion involves an evaluation of the specific facts of each case. In the Agency's view, the following qualitative criteria should be used to make such determinations on a case-by-case basis:

(1) Wastes from ancillary operations are not "uniquely associated" because they are not properly viewed as being "from" fossil fuel combustion.

(2) In evaluating a waste from non-ancillary operations, one must consider the extent to which the waste originates or derives from the fossil fuels, the combustion process, or combustion residuals, and the extent to which these operations impart chemical characteristics to the waste.

The low-volume wastes that are not uniquely associated with fossil fuel combustion would not be subject to today's regulatory determination. That is, they would not be accorded an exemption from RCRA subtitle C, whether or not they were co-managed with any of the exempted fossil fuel combustion wastes. Instead, they would be subject to the RCRA characteristic standards and hazardous waste listings. The exemption applies to mixtures of an exempt waste with a non-hazardous waste, but when an exempt waste is mixed with a hazardous waste, the mixture is not exempt.

Based on our identification and review of low volume wastes associated with the combustion of fossil fuels, we are considering offering the following guidance concerning which low volume wastes are uniquely associated with and which are not uniquely associated with fossil fuel combustion. Unless there are some unusual site-specific circumstances, we would generally consider that the following lists of low volume wastes are uniquely and non-uniquely associated wastes:

Uniquely Associated

- Coal Pile Runoff
- Coal Mill Rejects and Waste Coal
- Air Heater and Precipitator Washes
- Floor and Yard Drains and Sumps
- Wastewater Treatment Sludges
- Boiler Fireside Chemical Cleaning Wastes

Not Uniquely Associated

- Boiler Blowdown
- Cooling Tower Blowdown and Sludges
- Intake or Makeup Water Treatment and Regeneration Wastes
- Boiler Waterside Cleaning Wastes
- Laboratory Wastes
- General Construction and Demolition Debris
- General Maintenance Wastes

Moreover, we do not generally consider spillage or leakage of materials used in the processes that generate these non-uniquely associated wastes, such as boiler water treatment chemicals, to be uniquely associated wastes, even if they occur in close proximity to the fossil fuel wastes covered by this regulatory determination.

An understanding of whether a waste is uniquely associated can be important in one circumstance. If a waste is not uniquely associated and is a hazardous waste, co-managment with a Bevill waste will result in loss of the Bevill exemption. As a general matter, the wastes identified above as potentially not uniquely associated do not tend to be hazardous. This issue may therefore not be critical. The Agency, however, must still define appropriate boundaries for the Bevill exemption, because there is no authority to grant Bevill status to wastes that are not uniquely associated—the exemption was not intended as an umbrella for wastes that other industries must treat as hazardous.

EPA solicits comment on this discussion of uniquely associated wastes in the context of fossil fuel combustion and will issue final guidance after reviewing and evaluating information we receive as a result of this request.

E. Who Is Affected by Today's Action and How Are They Affected?

As explained above, fossil fuel combustion wastes generated from the combustion of coal, oil and natural gas will continue to remain exempt from being regulated as hazardous wastes under RCRA. No party is affected by today's determination to develop regulations applicable to coal combustion wastes when they are land disposed or used to fill surface or underground mines because today's action does not impose requirements. However, if such regulations are promulgated, they would affect coal combustion wastes subject to today's regulatory determination as well as wastes covered by the Part 1 regulatory determination when they are disposed in landfills and surface impoundments, or when used to fill surface or underground mines.

While we do not intend that national subtitle D regulations would be applicable to oil combustion wastes, we intend to work with relevant stakeholders so that any necessary measures are taken to ensure that oil combustion wastes currently managed in the two known remaining unlined surface impoundments are managed in a manner that protects human health and the environment.

F. What Additional Actions Will EPA Take After this Regulatory Determination Regarding Coal, Oil and Natural Gas Combustion Wastes?

To ensure that entities who generate and/or manage fossil fuel combustion wastes provide long-term protection of human health and the environment, we plan several actions:

- We will review comments submitted in response to today's notice on uniquely associated wastes and on the adequacy of the guidance developed by the utility industry on co-management of mill rejects (pyrites) with large volume coal combustion wastes.
- We will work with the State of Massachusetts and the owners and operators of the remaining two oil combustion facilities that currently manage their wastes in unlined surface impoundments to ensure that any necessary measures are taken so these wastes are managed in a manner that protects human health and the environment (described in section 3.D. of this document).
- We are evaluating the groundwater model and modeling methods that were used in the RTC to estimate risks for these wastes. This review may result in a re-evaluation of the potential groundwater risks posed by the management of fossil fuel combustion wastes and action to revise our Part 1 and Part 2 determinations if appropriate (see section 2.C. of this document).
- There are a number of ongoing and evolving efforts underway at EPA to improve our understanding of the human health impacts of wastes used in agricultural settings. We expect to receive substantial comments and new scientific information based on a risk assessment of the use of cement kiln dust as a substitute for agricultural lime (see 64 FR 45632; August 20, 1999) and other Agency efforts. As a result, we may refine our methodology for assessing risks related to the use of wastes in agricultural settings. If these efforts lead us to a different understanding of the risks posed by fossil fuel combustion wastes when used as a substitute for agricultural lime, we will take appropriate action to reevaluate today's regulatory determination (see section 2.C. of this document).
- We will review the findings and recommendations of the National Academy of Sciences upcoming report on mercury and assess its implications on risks due to exposure to mercury. We will ensure that the regulations we develop as a result of today's regulatory determination address any additional

risks posed by these wastes if hazardous constituent levels exceed acceptable levels

- We will reevaluate risk posed by managing coal combustion solid wastes if levels of mercury or other hazardous constituents change due to any future Clean Air Act air pollution control requirements for coal burning utilities (see section 2.C. of this document).
- We will continue EPA's partnership with the states to finalize voluntary industrial solid waste management guidance that identifies baseline protective practices for industrial waste management units, including fossil fuel combustion waste management units. We will use relevant information and knowledge that we obtain as a result of this effort to assist us in developing national regulations applicable to coal combustion wastes.

2. What Is the Basis for EPA's Regulatory Determination for Coal Combustion Wastes?

A. What Is the Agency's Decision Regarding the Regulatory Status of Coal Combustion Wastes and Why Did EPA Make That Decision?

We have determined at this time that regulation of coal combustion wastes under subtitle C is not warranted. However, we have also decided that it is appropriate to establish national regulations under non-hazardous waste authorities for coal combustion wastes that are disposed in landfills and surface impoundments. We believe that subtitle D regulations are the most appropriate mechanism for ensuring that these wastes disposed in landfills and surface impoundments are managed safely.

EPA's conclusion that some form of national regulation is warranted to address these wastes is based on the following considerations: (a) The composition of these wastes could present danger to human health and the environment under certain conditions, and "potential" damage cases identified by EPA and commenters, while not definitively demonstrating damage from coal combustion wastes, may indicate that these wastes have the potential to pose such danger; (b) we have identified eleven documented cases of proven damages to human health and the environment by improper management of these wastes in landfills and surface impoundments; (c) present disposal practices are such that, in 1995, these wastes were being managed in 40 percent to 70 percent of landfills and surface impoundments without reasonable controls in place, particularly in the area of groundwater monitoring; and (d) while there have been substantive improvements in state regulatory programs, we have also identified gaps in state oversight.

When we considered a tailored subtitle C approach, we estimated the potential costs of regulation of coal combustion wastes (including the utility coal combustion wastes addressed in the 1993 Part 1 determination) to be $1 billion per year. While large in absolute terms, we estimate that these costs are less than 0.4 percent of industry sales. To improve our estimates we solicit public comment on the potential compliance costs to coal combustion waste generators as well as the indirect costs to users of these combustion by-products.

We have also decided that it is appropriate to establish national regulations under RCRA non-hazardous waste authorities (and/or possibly modifications to exiting regulations established under authority of SMCRA) applicable to the placement of coal combustion wastes in surface or underground mines. We have reached this decision because (a) we find that these wastes when minefilled could present a danger to human health and the environment under certain circumstances, and (b) there are few states that currently operate comprehensive programs that specifically address the unique circumstances of minefilling, making it more likely that damage to human health or the environment could go unnoticed.

With the exception of minefilling as described above, we have decided that national regulation under subtitle C or subtitle D is not warranted for any of the other beneficial uses of coal combustion wastes. We have reached this decision because: (a) We have not identified any other beneficial uses that are likely to present significant risks to human health or the environment; and (b) no documented cases of damage to human health or the environment have been identified. Additionally, we do not want to place any unnecessary barriers on the beneficial uses of coal combustion wastes so they can be used in applications that conserve natural resources and reduce disposal costs.

B. What Were EPA's Tentative Decisions as Presented in the Report to Congress?

On March 31, 1999, EPA indicated a preliminary decision that disposal of coal combustion wastes should remain exempt from regulation under RCRA subtitle C. We also presented our tentative view that most beneficial uses of these wastes should remain exempt from regulation under RCRA subtitle C. However, in the RTC we identified three situations where we had particular concerns with the disposition or uses of these wastes.

First, we indicated some concern with the co-management of mill rejects ("pyrites") with coal combustion wastes which, under certain circumstances, could cause or contribute to ground water contamination or other localized environmental damage. We indicated that the utility industry responded to our concern by implementing a voluntary education and technical guidance program for the proper management of these wastes. We expressed satisfaction with the industry program and tentatively concluded that additional regulation in this area was not necessary. We explained that we were committed to overseeing industry's progress on properly managing pyritic wastes, and would revisit our regulatory determination relative to co-management of pyrites with large volume coal combustion wastes at a later date, if industry progress was insufficient in this area.

Second, in the RTC we identified potential human health risks from arsenic when these wastes are used for agricultural purposes (*e.g.,* as a lime substitute). To address this risk, we indicated our preliminary view that Subtitle C regulations may be appropriate for this management practice. We explained that an example of such controls could include regulation of the content of these materials such that, when used for agricultural purposes, the arsenic level could be no higher than that found in agricultural lime. As an alternative to subtitle C regulation, we indicated that EPA could engage the industry to implement a voluntary program to address the risk, for example, by limiting the level of arsenic in coal combustion wastes when using them for agricultural purposes. Moreover, we indicated that a decision to establish hazardous waste regulations applicable to agricultural uses of co-managed coal combustion wastes would likely affect the regulatory status of the Part 1 wastes (i.e., electric utility high volume coal combustion wastes managed separately from other coal combustion wastes) when used for agricultural purposes. This is because the source of the identified risk was the arsenic content of the high volume coal combustion wastes and not other materials that may be co-managed with them.

Third, we expressed concern with potential impacts from the expanding practice of minefilling coal combustion wastes (i.e., backfilling the wastes into mined areas) and described the difficulties we had with assessing the impacts and potential risks of this practice. We explained that these difficulties include:

- Determining if elevated contaminants in ground water are due to minefill practices or pre-existing conditions resulting from mining operations,
- Trying to model situations that may be more complex than our groundwater models can accommodate,
- The lack of long-term experience with the recent practice of minefilling, which limits the amount of environmental data for analysis, and
- The site-specific nature of these operations.

Accordingly, we did not present a tentative decision in the RTC for this practice. We indicated that subtitle C regulation would remain an option for minefilling, but that we needed additional information prior to making a final decision. Rather, we solicited additional information from commenters on these and other aspects of minefilling practices and indicated we would carefully consider that information in the formulation of today's decision.

C. How Did Commenters' React to EPA's Tentative Decisions and What Was EPA's Analysis of Their Comments?

Commenter's provided substantial input and information on several aspects of our overall tentative decision to retain the exemption for these wastes from RCRA subtitle C regulation. These aspects are: modeling and risk assessment for the groundwater pathway, documented damage cases, the potential for coal combustion waste characteristics to change as a result of possible future Clean Air Act regulations, proper management of mill rejects (pyrites), agricultural use of coal combustion wastes, the practice of minefilling coal combustion wastes, and our assessment of existing State programs and industry waste management practices.

1. How Did Commenters React to the Groundwater Modeling and Risk Assessment Analyses Conducted by EPA To Support its Findings in the Report to Congress?

Comments. Industry and public interest group commenters submitted detailed critiques of the groundwater model, EPACMTP, that we used for our risk analysis. Industry commenters believe that the model will overestimate the levels of contaminants that may migrate down-gradient from disposed wastes. Environmental groups expressed the opposite belief; that is, that the model underestimates down-gradient chemical concentrations and, therefore, underestimates the potential risk posed by coal combustion wastes.

The breadth and potential implications of the numerous technical comments on the EPACMTP model are significant. Examples of the comments include issues relating to:

- The thermodynamic data that are the basis for certain model calculations,
- The model's ability to account for the effects of oxidation-reduction potential,
- The model's ability to account for competition between multiple contaminants for adsorption sites,
- The model's algorithm for selecting adsorption isotherms,
- The impact of leachate chemistry on adsorption and aquifer chemistry, and
- The model's inherent assumptions about the chemistry of the underlying aquifer.

EPA's Analysis of the Comments. We have been carefully reviewing all of the comments on the model. We determined that the process of thoroughly investigating all of the comments will take substantially more time to complete than is available within the court deadline for issuing this regulatory determination. At this time, we are uncertain of the overall outcome of our analysis of the issues raised in the comments. Accordingly, we have decided not to use the results of our groundwater pathway risk analysis in support of today's regulatory determination on fossil fuel combustion wastes. As explained below, in making today's regulatory determination, we have relied in part on other information related to the potential danger that may result from the management of fossil fuel combustion wastes.

Meanwhile, we will continue with our analysis of comments on the groundwater model and risk analysis. This may involve changing or re-structuring various aspects of the model, if appropriate. It may also include additional analyses to determine whether any changes to the model or modeling methodology would materially affect the groundwater risk analysis results that were reported in the RTC. If our investigations reveal that a re-analysis of groundwater risks is appropriate, we will conduct the analysis and re-evaluate today's decisions as warranted by the re-analysis.

In addition to our ongoing review of comments on the groundwater model, one element of the model—the metals partitioning component called "MINTEQ"—has been proposed for additional peer review. When additional peer review is completed, we will take the findings and recommendations into account in any overall decision to re-evaluate today's regulatory determination.

While not relying on the EPACMTP groundwater modeling as presented in the RTC, we have since conducted a general comparison of the metals levels in leachate from coal combustion wastes to their corresponding hazardous waste toxicity characteristic levels. Fossil fuel wastes infrequently exceed the hazardous waste characteristic. For co-managed wastes, 2% (1 of 51 samples) exceeded the characteristic level. For individual wastes streams, 0% of the coal bottom ash, 2% of the coal fly ash, 3% of the coal flue gas desulfurization, and 7% of the coal boiler slag samples that were tested exceeded the characteristic level. Nevertheless, once we have completed a review of our groundwater model and made any necessary changes, we will reevaluate groundwater risks and take appropriate regulatory actions. We will specifically assess new modeling results as they relate to any promulgated changes in the arsenic MCL.

We also compared leach concentrations from fossil fuel wastes to the drinking water MCLs. In the case of arsenic, we examined a range of values because EPA expects to promulgate a new arsenic drinking water regulation by January 1, 2001. This range includes the existing arsenic MCL (50 ug/l), a lower health based number presented in the FFC Report to Congress (RTC) (0.29 ug/l), and two assumed values in between (10 and 5 ug/l). We examined this range of values because of our desire to bracket the likely range of values that EPA will be considering in its effort to revise the current MCL for arsenic. The National Research Council's 1999 report on Arsenic in Drinking Water indicated that the current MCL is not sufficiently protective and should be revised downward as soon as possible. For this reason, we selected the current MCL of 50 ug/L for the high end of the range because EPA is now considering lowering the current MCL and does not anticipate that the current MCL would be revised to any higher value. We selected the health-based number presented in the Report to Congress for the low end of the range because we believe this represents the lowest concentration that would be considered in revising the current MCL. Because at this time we cannot project a particular value as the eventual MCL, we also examined values in between these low-end and high-end values, a value of 5 ug/L and a value of 10 ug/L, for our analyses supporting today's regulatory determination. The choice of these mid-range values for analyses does not predetermine the final MCL for arsenic.

Those circumstances where the leach concentrations from the wastes exceed the drinking water criteria have the greatest potential to cause significant risks. This ''potential'' risk, however, may not occur at actual facilities. Pollutants in the leachate of the wastes undergo dilution and attenuation as they migrate through the ground. The primary purpose of models such as EPACMTP is to account for the degree of dilution and attenuation that is likely to occur, and to obtain a realistic estimate of the concentration of contaminants at a groundwater receptor. To provide a view of potential groundwater risk, we tabulated the number of occurrences where the waste leachate hazardous metals concentrations were: (a) Less than the criteria, (b) between 1 and 10 times the criteria, (c) between 10 and 100 times the criteria, and (d) greater than 100 times the criteria. Groundwater models that we currently use, when applied to large volume monofill sources of metals, frequently predict that dilution and attenuation will reduce leachate levels on the order of a factor of 10 under reasonable high end conditions. This multiple is commonly called a dilution and attenuation factor (DAF). For this reason and because lower dilution and attenuation factors (*e.g.,* 10) are often associated with larger disposal units such as those typical at facilities where coal is burned, we assessed the frequency of occurrence of leach concentrations for various hazardous metals which were greater than 10 times the drinking water criteria. Based on current MCLs, there was only one exceedence (for cadmium). However, when we considered the arsenic health based criterion from the RTC, we found that a significant percentage (86%) of available waste samples had leach concentrations for arsenic that were greater than ten times the health-based criterion. Even considering intermediate values closer to the current MCL, a significant percentage of available waste samples had leach concentrations for arsenic that were greater than ten times the criteria (30% when the criterion was assumed to be 5 ug/l, and 14% when the criterion was assumed to be 10 ug/l). Similar concerns also occurred when comparing actual groundwater samples associated with FFC waste units and this range of criteria for arsenic. We believe this is an indication of potential risks from arsenic.

For the above analysis, we used a value equal to half the detection level to deal with those situations where analyses resulted in ''less than detection'' values that exceeded the MCL criteria. The actual concentration may be as low as zero or up to the detection level. To illustrate the impact of this assumption, an analysis was performed setting the ''less than detection'' values to zero, and an arsenic criteria at 50 ug/l. While 30% of the values exceeded 10 times the criteria when using half the detection level, exceedences dropped to 13% when ''less than detection'' values were set to zero.

The comparison of the leachate levels to 10 times MCL criteria is a screening level analysis that supports our concerns, which are primarily based on damage cases and the lack of installed controls (liners and groundwater monitoring). We recognize, however, that prior to issuing a regulation the Agency expects to address the issues raised on the groundwater model and complete a comprehensive groundwater modeling effort. Furthermore, we anticipate that uncertainty regarding whether the arsenic MCL will be amended and to what level, will be more settled prior to regulation of these wastes. These factors could heighten or reduce concerns with regard to the need for Federal regulation of fossil fuel combustion wastes.

2. How Did Commenters React to EPA's Assessment of Documented Damage Cases Presented in the Report to Congress?

Prior to issuing the RTC, we sought and reviewed potential damage cases related to these particular wastes. The activities included:

- A re-analysis of the potential damage cases identified during the Part 1 determination,
- A search of the CERCLA Information System for instances of these wastes being cited as causes or contributors to damages,
- Contacts and visits to regulatory agencies in five states with high rates of coal consumption to review file materials and discuss with state officials the existence of damage cases,
- A review of information provided by the Utility Solid Waste Act Group and the Electric Power Research Institute on 14 co-management sites, and
- A review of information provided by the Council of Industrial Boiler Owners on eight fluidized bed combustion (FBC) facilities.

These activities yielded three damage case sites in addition to the four cases initially identified in the Part 1 determination.[2] Five of the damage cases involved surface impoundments and the two other cases involved landfills. The waste management units in these cases were all older, unlined units. The releases in these cases were confined to the vicinity of the facilities and did not affect human receptors. None of the damages impacted human health. We did not identify any damage cases that were associated with beneficial use practices.

Comments. Public interest group commenters criticized our approach to identifying damage cases associated with the management of fossil fuel combustion (FFC) wastes, stating that EPA did not use the same procedure used to identify damage cases for the cement kiln dust (CKD) Report to Congress. These commenters believed that we were too conservative in our interpretation and determination of FFC damage cases and dismissed cases that commenters believe are relevant instances of damage. For example, these commenters indicated that EPA, in the RTC, did not consider cases where the only exceedences of ground water standards were for secondary MCLs (Maximum Contaminant Levels as established by EPA for drinking water standards). They further indicated that the states often require ground water monitoring only for secondary MCL constituents and that elevated levels of the secondary MCL constituents are an indication of future potential for more serious, health-based standards to be exceeded for other constituents in the wastes, such as toxic metals. Additionally, these commenters stated that the Agency's analysis for damage cases was incomplete and they provided information on 59 possible damage cases involving these wastes, mostly at utilities. Additionally, commenters submitted seven cases of ecological damage that allege damage to mammals, amphibians, fish, benthic layer organisms and plants from co-management of coal combustion wastes in surface impoundments.

Industry commenters cited EPA's finding of so few damage cases as important support for our tentative conclusion to exempt these wastes from hazardous waste regulation. Further, some of the industry commenters indicated that the few damage cases that EPA identified do not represent current

[2] The Part 1 determination identified six cases of documented damages. Upon further reveiw, we determined that two of these cases involve utility coal ash monofills which are covered by the Part 1 determination. However, the other four cases involved remaining wastes that are covered by today's determination.

utility industry management practices, but rather reflect less environmentally protective management practices at older facilities that pre-date the numerous state and federal requirements that are now in effect for managing these wastes.

EPA's Analysis of the Comments. Regarding ecological damage, while we did not identify any ecological damage cases in the RTC associated with management of coal combustion wastes, we reviewed the information on ecological damage submitted by commenters and agree that four of the seven submitted are documented damage cases that involve FFC wastes. All of these involve some form of discharge from waste management units to nearby lakes or creeks. These confirm our risk modeling conclusions as presented in the RTC that there could be adverse impacts on amphibians, birds, or mammals if they were subject to the elevated concentrations of selected chemicals that had been measured in some impoundments. However, no information was submitted in comments that would lead us to alter our conclusion that these threats are not substantial enough to cause large scale, system level ecological disruptions. These damage cases, attributable to runoff or overflow that is already subject to Clean Water Act discharge or stormwater regulations, are more appropriately addressed under the existing Clean Water Act requirements.

Regarding our assessment of damage to ground water, we believe our approach to FFC damage cases in the RTC was consistent with the approach we used for identifying CKD damage cases. For CKD, we established two categories of damage cases—''proven'' damage cases and ''potential'' damage cases. Proven damage cases were those with documented MCL exceedences that were measured in ground water at a sufficient distance from the waste management unit to indicate that hazardous constituents had migrated to the extent that they could cause human health concerns. Potential damage cases were those with documented MCL exceedences that were measured in ground water beneath or close to the waste source. In these cases, the documented exceedences had not been demonstrated at a sufficient distance from the waste management unit to indicate that waste constituents had migrated to the extent that they could cause human health concerns. We do not believe that it would be appropriate to consider an exceedence directly beneath a waste management unit or very close to the waste boundary to be a documented, proven damage case. State regulations typically use a compliance procedure that relies on measurement at a receptor site or in ground water at a point beyond the waste boundary (*e.g.,* 150 meters). While our CKD analysis did not distinguish between primary and secondary MCL exceedences, most CKD damage cases involved a primary MCL constituent. Our principal basis for determining that CKD when managed in land-based units would no longer remain exempt from being regulated as a hazardous waste was our concern about generally poor management practices characteristic of that industry. Our conclusion was further supported by the extremely high percentage of proven damage cases occurring at active CKD sites for which groundwater monitoring data were available.

For FFC, we used the same test of proof to identify possible damage cases. Our FFC analysis drew a distinction between primary and secondary MCL exceedences because we believe this factor is appropriate in weighing the seriousness of FFC damage in terms of indicating risk to human health and the environment. For FFC, in the RTC, we reported only the ''proven'' damage (*i.e.,* exceedence of a health-based standard such as a primary MCL and measurement in ground water or surface water). As was done in the CKD analysis, we also identified a number of potential FFC damage cases (eleven) which were included in the background documents that support the RTC.

Unlike the primary MCLs, secondary MCLs are not based on human health considerations. (Examples are dissolved solids, sulfate, iron, and chloride for which groundwater standards have been established because of their effect on taste, odor, and color.) While some commenters believe that elevated levels of some secondary MCL parameters such as soluble salts are likely precursors or indicators of future hazardous constituent exceedences that could occur at coal combustion facilities, we are not yet able and will not be able to test their hypothesis until we complete our analysis of all comments received on our groundwater model and risk analysis, which will not be concluded until next year.

Of the 59 damage cases reported by commenters, 11 cases appear to involve exceedences of primary MCLs or other health-based standards as measured either in off-site ground water or in nearby surface waters, the criteria we used in the RTC to identify proven damage cases. Of these eleven cases, two are coal ash monofills which were included in the set of damage cases described by EPA in its record supporting the Part 1 regulatory determination. The remaining nine cases involve the co-management of large volume coal combustion wastes with other low volume and uniquely associated coal combustion wastes. We had already identified five of these nine cases in the RTC. Thus, only four of these eleven damage cases are newly identified to us. Briefly, the four new cases involve:

- Exceedence of a state standard for lead in downgradient ground water at a coal fly ash landfill in New York. There were also secondary MCL exceedences for sulfate, dissolved solids, and iron.
- Primary MCL exceedences for arsenic and selenium in downgradient monitoring wells for a coal ash impoundment at a power plant in North Dakota. There were also secondary MCL exceedences for sulfate and chloride.
- Primary MCL exceedences for fluoride and exceedence of a state standard for boron in downgradient monitoring wells at a utility coal combustion waste impoundment in Wisconsin. There was also a secondary MCL exceedence for sulfate.
- Exceedence of a state standard for boron and the secondary MCL for sulfate and manganese in downgradient monitoring wells at a utility coal combustion landfill in Wisconsin.

We found that in nine of the 11 proven damage cases (including one Superfund site), states took appropriate action to require or conduct remedial activities to reduce or eliminate the cause of contamination. EPA took action in the remaining two cases under the Superfund program

Nineteen of the candidate damage cases submitted by commenters involve either on-site or off-site exceedences of secondary MCLs, but not primary MCLs or other health-based standards. Consistent with our CKD analysis, we consider these cases to be indicative of a potential for damage to occur at these sites because they demonstrate that there has been a release to ground water from the waste management unit.

Regarding the remaining 29 cases submitted by commenters:

- Six involve primary MCL exceedences, but measurements were in ground water either directly beneath the waste or very close to the waste boundary, *i.e.,* no off-site ground water or receptor measurements indicated that ground water standards had been exceeded. Consistent with our analysis of damage cases for cement kiln dust, we consider these six cases to be indicative of a potential for damage to occur at these sites because they demonstrate that there has been a release to ground water from the waste management unit..

- Eighteen case summary submissions contained insufficient documentation and data for us to verify and draw a conclusion about whether we should consider these to be potential or proven damage cases. Of these 18 cases, commenters claimed that 11 cases involve primary MCL exceedences, and another two involve secondary MCLs, but not primary MCLs. The other five cases lacked sufficient information and documentation to determine whether primary or secondary MCLs are involved. Examples of information critical to assessing and verifying candidate damage cases that was not available for these particular cases include: Identification of the pollutants causing the contamination; identification of where or how the damage case information was obtained (*e.g.*, facility monitoring data, state monitoring or investigation, third party study or analysis); monitoring data used to identify levels of contaminants; and/or sufficient information to determine whether the damages were actually attributable to fossil fuel combustion wastes; and/or location of the identified contamination (*i.e.*, directly beneath the unit or very close to the waste boundary or at a point some distant (*e.g.*, 150 meters) from the unit boundary).
- Three case submissions are cases we identified in the Part 1 determination and involve monofilled utility coal ash wastes. However, as explained in the Report to Congress for the Part 1 determination, EPA determined that there was insufficient evidence to consider them to be documented damage cases.
- One case did not involve fossil fuel combustion wastes.
- One case involved coal combustion wastes and other unrelated wastes in an illegal, unpermitted dump site. This site was handled by the state as a hazardous waste cleanup site.

Our detailed analysis of the damage cases submitted by commenters is available in the public docket for this regulatory determination.

In summary, based on damage case information presented in the RTC and our review of comments, we conclude that there are 11 proven damage cases associated with wastes covered by today's regulatory determination. We identified seven of these damage cases in the RTC, so there are four new proven damage cases that were identified by commenters. All of the sites were at older, unlined units, with disposal occurring prior to 1993. For all 11 of the proven damage cases, either the state or EPA provided adequate follow-up to require or else undertake corrective action. Although these damage cases indicate that coal combustion wastes can present risks to human health and the environment, they also show the effectiveness of states' responses when damages were identified. None of these cases involved actual human exposure.

Additionally, we determined that another 25 of the commenter submitted cases are potential damage cases for the reasons described above. Thus, including the 11 potential damage cases that we identified in the background documents that support the RTC, we are aware of 36 potential damage cases. While we do not believe the latter 36 cases satisfy the statutory criteria of documented, proven damage cases because damage to human health or the environment has not been proven, we believe that these cases may indicate that these wastes pose a ''potential'' danger to human health and the environment in some circumstances.

In conclusion, while the absolute number of documented, proven damage cases is not large, we believe that the evidence of proven and potential damage should be considered in light of the proportion of new and existing facilities, particularly surface impoundments, that today lack basic environmental controls such as liners and groundwater monitoring. Approximately one-third of coal combustion wastes are managed in surface impoundments. We note that controls such as liners may not be warranted at some facilities, due to site-specific conditions. We acknowledge, however, that our inquiry into the existence of damage cases was focused primarily on a subset of states. Given the volume of coal combustion wastes generated nationwide and the number of facilities that lacked groundwater monitoring as of 1995, there is at least a substantial likelihood other cases of actual and potential damage likely exist. Because we did not use a statistical sampling methodology to evaluate the potential for damage, we are unable to determine whether the identified cases are representative of the conditions at all facilities and, therefore, cannot quantify the extent and magnitude of damages at the national level.

3. What Concerns Did Commenters Express About the Impact of Potential Future Regulation of Hazardous Air Pollutants Under the Clean Air Act on Today's Regulatory Determination?

Comments. In both public hearing testimony and written comments, public interest groups expressed concern about potential changes in the characteristics of these wastes when new air pollution controls are established under the Clean Air Act. The commenters referred to the possible future requirement for hazardous air pollutant controls at coal burning electric utility power plants, which could result in an increased level of metals and possibly other hazardous constituents in coal combustion wastes. The commenters indicated that these increased levels, in turn, could have serious implications for cross-media environmental impacts such as leaching to groundwater and volatilization to the air. The commenters argued that the Agency should include these factors in its current decision making on the regulatory status of coal combustion under the Resource Conservation and Recovery Act.

EPA's Analysis of the Comments. We have carefully considered the issue of cross-media impacts and the commenters' specific concerns that future air regulations could have an adverse impact on the characteristics of coal combustion wastes. We have concluded that it is premature to consider the possible future impact of such new air pollution controls on the wastes that are subject to today's regulatory determination. The Agency plans to issue a regulatory determination in the latter part of 2000 regarding hazardous air pollutant (HAP) controls at coal-burning, power generating facilities. If EPA decides to initiate a rulemaking process, final rulemaking under the Clean Air Act is projected to occur in 2004. Thus, no final decision has been made on what, if any, constituents will be regulated by future air pollution control requirements. Additionally, the regulatory levels of the those specific pollutants that might be controlled and the control technologies needed to attain any regulatory requirements have not yet been identified. Therefore, we believe there is insufficient information at this time for evaluating the characteristics and potential environmental impacts of solid wastes that would be generated as a result of new Clean Air Act requirements.

When any rulemaking under the Clean Air Act proceeds to a point where we can complete an assessment of the likely changes to the character of coal combustion wastes, we will evaluate the implications of these changes relative to today's regulatory determination and take appropriate action.

4. How Did Commenters React to the Findings Presented in the Report to Congress Related to Proper Management of Mill Rejects (Pyrites)?

The RTC explained that we identified situations where pyrite-bearing materials such as mill rejects (a low volume and uniquely associated waste) that are co-managed with coal combustion wastes may cause or contribute to risks or environmental damage if not managed properly. These materials when managed improperly with exposure to air and water can generate acid. The acid, in turn, can mobilize metals contained in the co-managed combustion wastes. The RTC also explained that the Agency engaged the utility industry in a voluntary program to ensure appropriate management of these wastes. The industry responded by developing technical guidance and a voluntary industry education program on proper management of these wastes.

Comments. Utility industry commenters supported our tentative decision to continue the exemption for coal combustion wastes co-managed with mill rejects from regulation as a hazardous waste. Their position is based primarily on the industry's voluntary implementation of an education program and technical guidance on the proper management of these wastes, as described in the RTC.

Public interest groups and other commenters disagreed with our tentative decision, explaining their belief that such voluntary controls or programs are inadequate. They indicated that coal combustion wastes should be subject to hazardous waste regulations.

EPA's Analysis of the Comments. We remain encouraged by the utility industry program to educate and inform its members by implementing guidance on the proper management of coal mill rejects. However, as pointed out by commenters, there is no assurance that facilities where coal combustion wastes co-managed with pyritic wastes will follow the guidance developed by industry. In light of the number of demonstrated and potential damage cases identified to date, we are concerned that simply relying on voluntary institution of necessary controls would not adequately ensure the protection of human health and the environment. At this time, to ensure that we are aware of all stakeholders views on the adequacy of the control approaches described in the guidance to protect human health and the environment, we are soliciting public comment on the final version of the industry coal mill rejects guidance. This guidance is available in the docket supporting today's decisions.

5. How Did Commenters React to the Findings Presented in the Report to Congress Related to Agricultural Use of Coal Combustion Wastes?

In the RTC, we presented findings on the human health risks associated with agricultural use of coal wastes as an agricultural lime substitute. The pathway examined embodies risks from ingestion of soil and inhalation, and from ingestion of contaminated dairy, beef, fruit and vegetable products. The resultant ''high end'' cancer risk reported in the RTC was 1×10^{-5} (one in one hundred thousand exposed population), for the child of a farmer. The variables held at high end for this calculation were contaminant concentration and children's soil ingestion. With all variables set to central tendency values, the risk was calculated to be 1×10^{-7} (one in ten million exposed population). We did not identify the presence of any non-cancer hazard of concern. Based on the high end risk, the Agency raised the possibility in the RTC of developing Subtitle C controls or seeking commitments from industry to a voluntary program.

Comments. A number of industry, academic, and federal agency commenters disagreed with our tentative conclusion that some level of regulation may be appropriate for coal combustion wastes when used as an agricultural soil supplement. They indicated that EPA used unrealistically conservative levels for four key inputs used in our risk analysis and that use of a realistic level for any one of these inputs would result in a risk level less than 1×10^{-6}. The four inputs identified by the commenters are: application rate of the wastes to the land, the rate of soil ingestion by children, the bioavailability of arsenic and the phytoavailability of arsenic.

These commenters further recommended that EPA not regulate, but rather encourage voluntary restrictions because:

- Agricultural use of coal combustion wastes creates no adverse environmental impacts and EPA identified no damage cases associated with this practice;
- Agricultural use of these wastes has significant technical and economic benefits;
- Federal controls would be unnecessarily costly and would create a barrier for research and development on the practice;
- Existing regulatory programs are sufficient to control any risks from this practice; and
- The limits suggested in the RTC for arsenic levels in coal combustion wastes are inconsistent with limits applied to other materials used in agriculture.

Public interest groups stated their belief that a voluntary approach would not be sufficiently protective of human health and the environment. They believe the Agency should apply restrictions on the use of these wastes in agriculture because the Agency's analyses of the risks and benefits of this practice were inadequate. They further recommended that EPA should prohibit the land application of coal combustion wastes generated by conventional boilers, and make the arsenic limitation of EPA's sewage sludge land application regulations applicable to the land application of coal combustion wastes generated by fluidized bed combustors, which add lime as part of the combustion process.

EPA's Analysis of Comments. After reviewing these comments and supporting information provided by the commenters, we concluded that a revised input into the model for children's soil ingestion rate is appropriate. Based on further review of the Agency's Exposure Factors Handbook (EFH), we decided to model a children's soil ingestion rate of 0.4 grams per day instead of the 1.4 grams per day that underlay the results given in the RTC.

Many studies have been conducted to estimate soil ingestion by children. Early studies focused on dirt present on children's hands. More recently, studies have focused on measuring trace elements in soil and then in feces as a function of internal absorption. These measurements are used to estimate amounts of soil ingested over a specified time period. The EFH findings for children's soil ingestion are based on seven key studies and nine other relevant studies that the Agency reviewed on this subject. These studies showed that mean values for soil ingestion ranged from 39 mg/day to 271 mg/day with an average of 146 mg/day. These results are characterized for studies that were for short periods with little information reported for pica behavior. To account for longer periods of time, the EFH reviewed the upper percentile ranges of the data studied and found ingestion rates that ranged from 106 mg/day to 1,432 mg/day with an average of 383 mg/day for soil ingestion. Rounding to one significant figure, the EFH recommended an upper percentile children's soil ingestion rate of 400 mg/day. The Agency believes that this recommendation is the best available information to address children's exposure through the soil ingestion route. Reducing the ingestion rate to the EFH handbook recommended level of

400 mg/day reduced the calculated risk to 3.4×10^{-6} for this one child risk situation and suggests that agricultural use of FFC wastes does not cause a risk of concern.

EPA believes its inputs for phytoavailability are accurate, although there are studies that suggest phytoavailability will decrease over time. Arsenic bioavailability is a function of all sources of arsenic and EPA believes it has characterized this accurately. However, as noted elsewhere, arsenic toxicity is now being studied by the Agency in conjunction with a proposed new arsenic MCL and may necessitate re-visiting today's judgement on agricultural use.

Our technical analysis that resulted in revised risk is explained in a document titled Reevaluation of Non-groundwater Pathway Risks from Agricultural Use of Coal Combustion Wastes, which is available in the docket for this action.

The comment on inappropriateness of application frequency was caused by a misunderstanding of the language in the RTC. The rate used was actually every two or three years, not two or three times per year.

Two ongoing studies of wastes of potential use as agricultural soil supplements relate to the use of FFC wastes for this purpose. Although these did not play a direct role in EPA's decision regarding FFC wastes, they are summarized below and may play a role in any future review of today's decision.

(1) On August 20, 1999, the agency proposed risk-based standards for cement kiln dust when used as a liming agent (see 64 FR 45632; August 20, 1999). This analysis was completed in 1998 just prior to our completion of the analysis of FFC wastes when used as agricultural supplements. The CKD analysis underwent a special peer review by a standing committee that is used by the Department of Agriculture. We were not able to respond to the peer review comments in either the CKD proposal or in our assessment for fossil fuel combustion wastes prior to publication of today's regulatory determination. The comment period for the CKD proposal closed on February 17, 2000, and we will soon begin our review and analyses of the public and peer review comments.

(2) In December 1999, EPA proposed new risk based standards for the use of municipal sewage sludge under section 503 of the Clean Water Act (the "503 standards"). It is important to note that municipal sludge has unique properties, application rates, and uses. This makes it inappropriate to transfer the 503 standards directly. Even though the standards cannot be used directly, there may be interest in the risk assessment methodologies used to support the development of these standards. We disagree that it is appropriate to establish an arsenic limitation for coal combustion ash when used for agricultural purposes equivalent to that contained in the EPA sewage sludge land application regulations. The organic nature of sewage sludge makes it behave very differently from inorganic wastes such as coal combustion wastes.

We conclude at this time that arsenic levels in coal combustion wastes do not pose a significant risk to human health when used for agricultural purposes. We expect to continue to review and refine the related risk assessments noted above, and will consider comments on the Agency's CKD and municipal sludge proposals, as well as new scientific developments related to this issue such as additional peer review of the EPA MINTEQ model that was used as a component of our risk analysis. If these efforts lead us to a different understanding of the risks posed by coal combustion wastes when used as a substitute for agricultural lime, we will take appropriate action to reevaluate today's regulatory determination.

6. How Did Commenters React to the Findings Presented in the Report to Congress Related to Minefilling of Coal Combustion Wastes?

In the RTC, we explained that we had insufficient information to adequately assess the risks associated with the use of coal combustion wastes to fill surface and underground mines, whether the mines are active or abandoned. Accordingly, we did not present a tentative conclusion in the RTC with respect to the use of coal combustion wastes for disposal in active mines or for reclamation of mines. However, we did indicate that regulation of minefilling under hazardous waste rulemaking authority would remain an option for minefilling, but that we needed additional information prior to making a final decision. Thus, we solicited additional information on specific minefilling techniques, problems that may be inherent in this management practice, risks posed by this practice, existing state regulatory requirements, and environmental monitoring data. We indicated that we would consider any comments and new information on minefilling received in comments and would address this management practice in today's regulatory determination.

Comments. A number of commenters responded to our request by providing reports on individual case studies, including minefilling in underground as well as in surface mines, descriptions of current state regulatory requirements that address this practice, monitoring data, and information about risk analysis techniques.

Industry commenters and one federal agency supported our decision to study the issue further and not attempt to estimate the risks posed by this practice using existing methods. Further, numerous industry, academic, state agency, and federal agency commenters encouraged EPA not to adopt national regulations or voluntary restrictions on minefilling because: (a) Nationwide standards would not be conducive to the site-specific evaluations needed to appropriately control these operations; (b) minefilling creates no adverse environmental impacts and EPA identified no damage cases associated with this practice; (c) existing state and federal regulatory programs and industry practices are sufficient to control any risks from this practice, and (d) federal standards would be an unreasonable interference with states' authorities.

Additionally, several industry representatives, legislators, and state mining and environmental agencies mentioned that this practice, when used to remediate abandoned mine lands, will produce considerably greater environmental benefits than risks. Further, they maintained that minefilling is a relatively inexpensive means to stop or even reverse the environmental damage caused by old mining practices. They indicated that through remediation by minefilling, these lands frequently can be returned to productive use. These commenters recommended no additional regulation of this practice.

Public interest groups and others believe we should regulate minefilling under RCRA subtitle C or prohibit it for several reasons including weaknesses in existing state and federal regulatory programs, the poor practices and performance at existing minefilling operations, and potential impacts on potable water sources. Commenters stated that state programs effectively allow open dumps without any design or construction standards. For minefilling, one commenter urged EPA to defer to state regulations only if the Agency specifically found existing state regulations to be adequate.

EPA's Analysis of Comments. We agree with commenters that it is inappropriate to estimate the risks posed by minefilling using the existing methods that we employed to conduct risk analyses for disposal of coal combustion wastes in landfills and impoundments. We found that the groundwater models available to us are unsuitable for estimating risks from minefills because, for example, they are not able to account for conditions such as fractured flow that are typical of the hydrogeology associated with mining operations. In addition, as explained above, EPA's primary groundwater model, EPACMTP, is now undergoing careful review on the basis of comments received on the Report to Congress.

We are aware that the use of coal combustion wastes to conduct remediation of mine lands can improve conditions caused by mining activities. We also recognize that this often is the lowest cost option for conducting these remediation activities. We generally encourage the practice of remediating mine lands with coal combustion wastes when minefilling is conducted properly and when there is adequate oversight of the remediation activities. We are also aware that relatively few states currently operate regulatory or other programs that specifically address minefilling, and that many states where this practice is occurring do not have programs in place. Based on our review of information on existing state minefill programs, we find serious gaps such as a lack of adequate controls and restrictions on unsound practices, *e.g.*, no requirement for groundwater monitoring and no control or prohibitions on waste placement in the aquifer.

At this time, we cannot reach definitive conclusions about the adequacy of minefilling practices employed currently in the United States and the ability of government oversight agencies to ensure that human health and the environment are being adequately protected. For example, it is often impossible to determine if existing groundwater quality has been impacted by previous mining operations or as a result of releases of hazardous constituents from the coal combustion wastes used in the minefilling applications. Additionally, data and information submitted during the public comment period indicate that if the chemistry of the mine relative to the chemistry of the coal combustion wastes is not properly taken into account, the addition of coal combustion wastes to certain environmental settings can lead to an increase in hazardous metals released into the environment. This phenomena has been substantiated by data available to the Agency that show when pyrites, which can cause acid generation, have been improperly co-managed with coal combustion wastes, high levels of metals, especially arsenic, have leached from the wastes.

Finally, we concluded in our recent study of disposal of cement kiln dust that placement of cement kiln dust directly in contact with ground water led to a substantially greater release of hazardous metal constituents than we predicted would occur when such placement in ground water did not occur. We are aware of situations where coal combustion wastes are being placed in direct contact with ground water in both underground and surface mines. This could lead to increased releases of hazardous metal constituents as a result of minefilling. Thus, if the complexities related to site-specific geology, hydrology, and waste chemistry are not properly taken into account when minefilling coal combustion wastes, we believe that certain minefilling practices have the potential to degrade, rather than improve, existing groundwater quality and can pose a potential danger to human health and the environment. Subsequent impacts on human health would depend in part on the proximity of drinking water wells, if any, to elevated levels of metals in the water. To date we are unaware of any proven damage cases resulting from minefilling operations.

7. How Did Commenters React to EPA's Tentative Reliance on State Programs and Voluntary Industry Implementation of Improved Management Practices To Mitigate Potential Risks From Coal Combustion Waste Management?

In the RTC, EPA considered retaining the exemption for coal combustion wastes disposed in surface impoundments and landfills and for mill rejects (pyrites) that are managed with those wastes. The Agency cited a reliance on state programs that have improved substantially over the past 10 to 15 years and continue to improve, combined with voluntary industry implementation of guidance for improved management practices to mitigate risk. In addition, we stated that we would continue to work with industries and states to promote and monitor improvements.

To assess the adequacy of state programs and the potential for voluntary implementation of improved practices, we looked at the current number of facilities with liners and groundwater monitoring (which may reflect voluntary industry upgrading as well as state requirements), and the number of state programs that currently have authority to require a broad range of environmental controls. For units operating as of 1995, we found that among utilities, slightly more than half of the disposal units were surface impoundments. Of these impoundments, 38 percent had groundwater monitoring and 26 percent had liners. Eighty-five percent of the utility landfills had groundwater monitoring and 57 percent had liners. For non-utility landfills, 94 percent had groundwater monitoring, and between 16 percent and 52 percent had liners. Between 1985 and 1995, 75 percent of new landfills and 60 percent of new surface impoundments within the utility sector had been lined. We have no information regarding the percentage of units built since 1995 (the date when the study we have relied on ended) that have liners or groundwater monitoring programs.

In looking at state programs, we found that for landfills, more than 40 states have the authority to require permits, siting restrictions, liners, leachate collection, groundwater monitoring, closure controls, and cover/dust controls. Forty-three states can require liners and 46 can require groundwater monitoring compared to 11 and 28 states, respectively, in the 1980's. For surface impoundments, more than 40 states have authority to require permits, siting restrictions, liners, groundwater monitoring, and closure control; 33 can require leachate collection (there is no earlier comparison data for surface impoundments). Forty-five states can require liners and 44 can require groundwater monitoring for impoundments.

Comments. Industry and state agency commenters generally stated that the Agency presented an accurate and comprehensive analysis of state programs and that existing state regulations are adequate. Public interest commenters raised many concerns about the adequacy of state programs: Either they do not have provisions to cover all elements of a protective program; they do not consistently impose the requirements for which they have authority; and/or enforcement is lax. Evidence commenters cited for the inadequacy of state programs included grandfathering for older management units and an apparent lack of controls for surface impoundments. For these reasons, some found EPA's review of state programs inaccurate or incomplete.

Public interest commenters were also skeptical of programs or efforts that rely on voluntary industry implementation because adherence to guidance is not guaranteed. Several commenters, primarily from industry, urged the Agency not to regulate pyrite co-management because of the voluntary, industry-developed guidance.

EPA's Analysis of Comments. We believe that state programs have, in fact, substantially improved over the last 15 years or so. A high percentage of states have authority to impose protective management standards on surface impoundments and landfills, especially for groundwater monitoring, liners, and leachate collection, which mitigate potential risks posed by these units. Over 40 states today have these authorities (33 states have authority to require leachate collection in surface impoundments). When authority under state groundwater and drinking water regulations are considered, some commenters have suggested that nearly all states can address the management of these wastes. In addition, we believe that the trend to line and install groundwater monitoring for new surface impoundments and landfills is positive. However, as some commenters noted, we acknowledge that our state program review looked at the authorities available to states and their overall regulatory requirements, not the specific requirements applied to given facilities, which could be more or less stringent. In addition, we recognize that individual state programs may have some gaps in coverage, as indicated below, so that some controls may not now be required at coal combustion waste impoundments and landfills. We would expect to see some differences in the application of requirements, depending on site-specific conditions.

One consistent trend that raises concern for the Agency is that controls are much less common at surface impoundment than at landfills. Even for newer units at utilities (constructed between 1985 and 1995), liners are used at 75 percent of landfills and only 60 percent of surface impoundments. Also at newer units, groundwater monitoring is implemented at 88 percent of landfills and at only 65 percent of surface impoundments. Approximately one-third of coal combustion wastes were managed in surface impoundments in 1995. Hydraulic pressure in a surface impoundment increases the likelihood of releases. We believe that groundwater monitoring, at a minimum, in existing as well as new impoundments, is a reasonable approach to monitor performance of the unit and a critical first step to addressing groundwater damage that may be caused by the unit. As of 1995, 38 percent of currently operating utility surface impoundments had groundwater monitoring and only 26 percent had liners.

While liners and groundwater monitoring are applied more frequently at landfills, there are still many utility and non-utility landfills that do not have liners. In addition, 15 percent of utility landfills do not have groundwater monitoring, and some six percent of non-utility landfills do not have groundwater monitoring, based on a limited survey.

The utility industry through its trade associations has demonstrated a willingness to work with EPA to develop protective management practices, and individual companies have committed to upgrading their own practices. However, the Agency recognizes that participation in voluntary programs is not assured. Also, individual facilities and companies may not implement protective management practices and controls, for a variety of reasons, in spite of their endorsement by industry-wide groups.

We see a trend toward significantly improving state programs and voluntary industry investment in liners and groundwater monitoring that we believe can mitigate potential risks over time. However, we identified significant gaps in controls already in place and, in particular, requirements that may be lacking in some states, either in authority to impose the requirements or potentially in exercising that authority. In response to comments, we further analyzed risks posed by coal combustion wastes taking into account waste characteristics and potential and actual damage cases. Based on these analyses, we concluded that coal combustion wastes, in certain circumstances, could unnecessarily increase risks to human health and the environment, and that a number of proven damages have been documented, and that more are likely if we had been able to conduct a more thorough search of available state records and if groundwater monitoring data were available for all units. We recognize there will probably continue to be some gaps in practices and controls and are concerned at the possibility that these will go unaddressed. We also believe the time frame for improvement of current practices is likely to be longer in the absence of federal regulations.

D. What Is the Basis for Today's Decisions?

Based on our collection and analysis of information reflecting the criteria in section 8002(n) of RCRA that EPA must consider in making today's regulatory determination, materials developed in preparing the RTC and supportive background materials, existing state and federal regulations and programs that affect the management of coal combustion wastes, and comments received from the public on the findings we presented in the RTC, we have concluded the following:

1. Beneficial Uses

To the extent coal combustion wastes are used for beneficial purposes, we believe they should continue to remain exempt from being regulated as hazardous wastes under RCRA. Beneficial purposes include waste stabilization, beneficial construction applications (*e.g.,* cement, concrete, brick and concrete products, road bed, structural fill, blasting grit, wall board, insulation, roofing materials), agricultural applications (*e.g.,* as a substitute for lime) and other applications (absorbents, filter media, paints, plastics and metals manufacture, snow and ice control, waste stabilization). For the reasons presented in section 3 below, we are separately addressing the use of coal combustion wastes to fill surface or underground mines.

For beneficial uses other than minefilling, we have reached this decision because: (a) We have not identified any beneficial uses that are likely to present significant risks to human health or the environment; and (b) no documented cases of damage to human health or the environment have been identified. Additionally, we do not want to place any unnecessary barriers on the beneficial use of coal combustion wastes so that they can be used in applications that conserve natural resources and reduce disposal costs.

Disposal can be burdensome and fails to take advantage of beneficial characteristics of fossil fuel combustion wastes. About one-quarter of the coal combustion wastes now generated are diverted to beneficial uses. Currently, the major beneficial uses of coal combustion wastes include: Construction (including building products, road base and sub-base, blasting grit and roofing materials) accounting for approximately 21%; sludge and waste stabilization and acid neutralization accounting for approximately 3%; and agricultural use accounting for 0.1%. Based on our conclusion that these beneficial uses of coal combustion wastes are not likely to pose significant risks to human health and the environment, we support increases in these beneficial uses of coal combustion wastes.

Off-site uses in construction, including wallboard, present low risk due to the coal combustion wastes being bound or encapsulated in the construction materials or because there is low potential for exposure. Use in waste and sludge stabilization and in acid neutralization are either regulated (under RCRA for hazardous waste stabilization or when placed in municipal solid waste landfills, or under the Clean Water Act in the case of municipal sewage sludge or wastewater neutralization), or appear to present low risk due to low exposure potential. While in the RTC, we expressed concern over risks presented by agricultural use, we now believe our previous analysis assumed unrealistically high-end conditions, and that the risk, which we now believe to be on the order of 10^{-6}, does not warrant national regulation of coal combustion wastes that are used in agricultural applications.

In the RTC, we were not able to identify damage cases associated with these types of beneficial uses, nor do we now believe that these uses of coal combustion wastes present a significant risk to human health or the environment. While some commenters disagreed with our findings, no data or other support for the commenters' position was provided, nor was any information provided to show risk or damage associated with agricultural use. Therefore, we conclude that none of the beneficial uses of coal combustion wastes listed above pose risks of concern.

2. Disposal in Landfills and Surface Impoundments

In this section, we discuss available information regarding the potential risks to human health and the environment from the disposal of coal combustion wastes into landfills and impoundments. In sum, our conclusion is these wastes can pose significant risks when mismanaged and, while significant improvements are being made in waste management practices due to increasing state oversight, gaps in the current regulatory regime remain.

We have determined that the establishment of national regulations is warranted for coal combustion wastes when they are disposed in landfills and surface impoundments, because: (a) The composition of these wastes has the potential to present danger to human health and the environment under some circumstances and "potential" damage cases identified by EPA and commenters, while not definitively demonstrating damage from coal combustion wastes, lend support to our conclusion that these wastes have the potential to pose such danger; (b) we have identified eleven cases of proven damage to human health and the environment by improper management of these wastes when land disposed; (c) while industry management practices have improved measurably in recent years, there is sufficient evidence these wastes are currently being managed in a significant number of landfills and surface impoundments without proper controls in place, particularly in the area of groundwater monitoring; and (d) while there have been substantive improvements in state regulatory programs, we have also identified significant gaps either in states' regulatory authorities or in their exercise of existing authorities. Moreover, we believe that the costs of complying with regulations that specifically address these problems, while large in absolute terms, are only a small percentage of industry revenues.

When we considered a tailored subtitle C regulatory approach, we estimated the potential costs of regulation of coal combustion wastes (including the utility coal combustion wastes addressed in the 1993 Part 1 determination) to be $1 billion per year. While large in absolute terms, we estimate that these costs are less than 0.4 percent of industry sales. Our preliminary estimate of impact on profitability is a function of facility size, among other factors. For the larger facilities, we estimate that reported pre-tax profit margins of about 13 percent may be reduced to about 11 percent. For smaller facilities, margins may be reduced from about nine percent to about seven percent.

We identified that the constituents of concern in these wastes are metals, particularly hazardous metals. We further identified that leachate from various large volume wastes generated at coal combustion facilities infrequently exceed the hazardous waste toxicity characteristic, for one or more of the following metals: arsenic, cadmium, chromium, lead, and mercury. Additionally, when we compared waste leachate concentrations for hazardous metals to their corresponding MCLs (or potential MCLs in the case of arsenic), we found that there was a potential for risk as a result of arsenic leaching from these wastes. The criteria we examined included the existing arsenic MCL, a lower health based number presented in the RTC, and two assumed values in between. We examined this range of values because, as explained earlier in this notice, EPA is in the process of revising the current MCL for arsenic to a lower value as a result of a detailed study of arsenic in drinking water and we wanted to assess the likely range of values that would be under consideration by EPA. Once we have completed a review of our groundwater model and made necessary changes, we will reevaluate the potential risks from metals in coal combustion wastes and compare any projected groundwater contamination to the MCLs that exist at that time.

We also identified situations where the improper management of mill rejects, a low volume and uniquely associated waste, with high volume coal combustion wastes has the potential to cause releases of higher quantities of hazardous metals. When these wastes are improperly managed, the mill rejects can create an acidic environment which enhances leachability and can lead to the release of hazardous metals in high concentrations from the co-managed wastes to ground water or surface waters. Thus, our analysis of the characteristics of coal combustion wastes leads us to conclude that these wastes have the potential to pose risk to human health and the environment. We also plan to address such waste management practices in our subsequent rulemaking.

Additionally, we identified 11 proven damage cases that documented disposal of coal combustion wastes in unlined landfills or surface impoundments that involved exceedences of primary MCLs or other health-based standards in ground water or drinking water wells. Three of the proven damage cases were on the EPA Superfund National Priorities List. Although these damage cases indicate that coal combustion wastes can present risks to human health and the environment, they also show the effectiveness of states' responses when damages were identified. All of the sites were at older, unlined units, with disposal occurring prior to 1993. None of these cases involved actual human exposure. Given the large number of facilities that do not now conduct groundwater monitoring, we have a concern that additional cases of damage may be undetected.

As detailed in the RTC and explained earlier in this notice, we identified that the states and affected industry have made considerable progress in recent years toward more effective management of coal combustion wastes. We also identified that the ability for most states to impose specific regulatory controls for coal combustion wastes has increased almost three-fold over the past 15 years. Forty-three states can now impose a liner requirements at landfills whereas 15 years ago, 11 had the same authority. In addition to regulatory permits, the majority of states now have authority to require siting controls, liners, leachate collection, groundwater monitoring, closure controls, and other controls and requirements for surface impoundments and landfills.

Nonetheless, we have concluded that there are still gaps in the actual application of these controls and requirements, particularly for surface impoundments. While most states now have the appropriate authorities and regulations to require liners and groundwater monitoring that would reduce or minimize the risks that we have identified, we have also identified numerous situations where these controls are not being applied. For example, only 26 percent of utility surface impoundments and 57 percent of utility landfills have liner systems in place. We have insufficient information to determine whether the use of these controls is significantly different for non-utility disposal units, due to a small sample size.

While many of these unlined units may be subject to grandfathering provisions that allow them to continue to operate without being lined, or may not need to be lined due to site-specific conditions, we are especially concerned that a substantial number of units do not employ groundwater monitoring to ensure that if significant releases occur from these unlined units, they will be detected and controlled. In 1995, groundwater was monitored at only 38 percent of utility surface impoundments. While monitoring is more frequent at landfills, there are still many units at which releases of hazardous metals could go undetected. For example, of the approximately 300 utility landfills, 45 newer landfills (15%) do not monitor ground water. We are concerned that undetected releases could cause exceedences of drinking water or other health-based standards that may threaten public health or groundwater and surface water resources. Thus, we conclude that national regulations would lead to substantial improvements in the management of coal combustion wastes.

3. Minefilling

We have determined that the establishment of national regulations is warranted for coal combustion wastes when they are placed in surface or underground mines because: (a) We wind that these wastes when minefilled have the potential to present a danger to human health and the environment, (b) minefilling of these wastes has been an expanding practice and there are few states that currently operate comprehensive programs that specifically address the unique circumstances of minefilling, making it more likely that any damage to human health or the environment would go unnoticed or unaddressed, and (c) we believe that the cost of complying with regulations that address these potential dangers may not have a substantial impact on this practice because minefilling continues to grow in those few states that already have comprehensive programs.

We recognize that at this time, we cannot quantify the nature of damage that may be occurring or may occur in the future as a result of using coal combustion wastes as minefill. It is often impossible to determine if existing groundwater quality has been impacted by previous mining operations or as a result of releases of hazardous constituents from the coal combustion wastes used in minefilling applications. We have not as yet identified proven damage cases resulting from the use of coal combustion wastes for minefilling.

We also acknowledge that when the complexities related to site-specific geology, hydrology, waste chemistry and interactions with the surrounding matrix, and other relevant factors are properly taken into account, coal combustion wastes used as minefill can provide significant benefits. However, when not done properly, minefilling has the potential to contaminate ground water to levels that could damage human health and the environment. Based on materials submitted during the public comment period, coal combustion wastes used as minefill can lead to increases in hazardous metals released into ground water if the acidity within the mine overwhelms the capacity of the coal combustion wastes to neutralize the acidic conditions. This is due to the increased leaching of hazardous metals from the wastes. The potential for this to occur is further supported by data showing that management of coal combustion wastes in the presence of acid-generating pyritic wastes has caused metals to leach from the combustion wastes at much higher levels than are predicted by leach test data for coal combustion wastes when strongly acidic conditions are not present. Such strongly acidic conditions often exist at mining sites.

Although we have identified no damage cases involving minefilling, we are also aware of situations where coal combustion wastes are being placed in direct contact with ground water in both surface and underground mines. We concluded in our recent study of cement kiln dust management practices that placement of cement kiln dust in direct contact with ground water led to a substantially greater release of hazardous metals than we predicted would occur when the waste was placed above the water table. For this reason, we find that there is a potential for increased releases of hazardous metals as a result of placing coal combustion wastes in direct contact with groundwater. Also, there are damage cases associated with coal combustion wastes in landfills. The Agency believes it is reasonable to be concerned when similar quantities of coal combustion wastes are placed in mines, which often are not engineered disposal units and in some cases involve direct placement of wastes into direct contact with ground water.

We are concerned that government oversight is necessary to ensure that minefilling is done appropriately to protect human health and the environment, particularly since minefilling is a recent, but rapidly expanding use of coal combustion wastes. Government oversight has not yet "caught up" with the practice consistently across the country. There are some states that have programs that specifically address minefilling practices. We are likely to find that their programs or certain elements of their programs could serve as the basis for a comprehensive, flexible set of national management standards that ensure protection of human health and the environment. We also believe that these state programs will provide valuable experience in coordinating with SMCRA program requirements. However, at this time, few of the programs are comprehensive. Commenters pointed out, and we agree, there are significant gaps in other states. We believe that additional requirements for long-term groundwater monitoring, and controls on wastes placed directly into groundwater might be prudent.

E. What Approach Will EPA Take in Developing National Regulations?

We will not promulgate any regulations for beneficial uses other than minefilling. We do not wish to place any unnecessary barriers on the beneficial use of fossil fuel combustion wastes so that they can be used in applications that conserve natural resources and reduce disposal costs.

Once we concluded there is a need for some form of national regulation of coal combustion wastes disposed in landfills and surface impoundments and used as minefill, we considered two approaches. One approach would involve promulgating subtitle D regulations, pursuant to sections 1008 and 4004(a) of RCRA, that would contain criteria defining landfills and impoundments that would constitute "sanitary landfills." Any facility that failed to meet the standards would constitute an open dump, which is prohibited by section 4005(a) of RCRA. Such standards would set a consistent baseline for protective management throughout the country. We would also work with the Department of Interior, Office of Surface Mining to evaluate whether equivalent protectiveness for minefilling could be afforded by relying on revision of existing SMCRA regulations or by relying on a combination of RCRA and SMCRA authorities.

The second approach was to promulgate regulations pursuant to Subtitle C of RCRA, that would have been similar to our recent proposed regulation of cement kiln dust. Following this approach, EPA would develop national management standards based on the Subtitle D open dump criteria as discussed above, as well as a set of tailored Subtitle C requirements promulgated pursuant to RCRA section 3004(x). If the wastes were properly managed in accordance with the subtitle D-like standards, they would not be classified as hazardous wastes. When they were not properly managed, they would become listed hazardous wastes subject to tailored subtitle C standards. This scheme would be effective in each state authorized for the hazardous waste program when that state modified its hazardous waste program to incorporate the listing.

Under this approach, after states have adopted the contingent listing, facilities that have egregious or repeated violations of the management standards would be moved into the subtitle C program (subject to the tailored RCRA 3004 (x) requirements, rather than to the full set of subtitle C requirements). Thus, EPA would have authority to enforce the management standards.

The decision whether to establish regulations under subtitle C or D of RCRA for disposal of coal combustion wastes in landfills and surface impoundments and when minefilled was a difficult one. EPA believes that, in this case, either approach would ensure adequate protection of public health and the environment. Either subtitle C or D provides EPA with the authority to prescribe protective standards for the management of these wastes. Moreover, as described above, the standards that EPA would adopt under either regime, because of the flexibility provided by section 3004 (x), would be substantively the same. Also, under either approach, a facility that fails to comply with the standards is in violation of RCRA—in the case of subtitle C, the facility would be in violation of the tailored standards promulgated under section 3004(x). In the case of subtitle D, the facility would be in violation of the prohibition in section 4005(a) of RCRA against "open dumping." The prohibition against open dumping is, however, enforceable only by private citizens and states, not EPA. Management standards established under the authority of subtitle C (including tailored section 3004(x) standards) are also enforceable by EPA. It appears that more than 40 states already have sufficient authority to implement most, if not all of the national standards we contemplate would be appropriate for surface impoundments and landfills. One difference between the two regimes may be that states could cite revised subtitle D standards as a basis for exercising their existing authorities more vigorously, potentially promoting swifter adoption of appropriate controls for surface impoundments and landfills. In addition, subtitle D standards would be applicable and enforceable by citizens as soon as the federal rule becomes effective. subtitle C standards in contrast, would not apply until incorporated into state subtitle C programs. For minefilling, we would also explore SMCRA as a possible mechanism to speed implementation, even if we relied on subtitle D to establish protective standards, because minefilling operations already are subject to SMCRA permitting authority.

Taking into account the common and distinct features of these alternative approaches, EPA believes at this time, based on the current record, that subtitle D regulations are the more appropriate mechanism for a number of reasons. In view of the very substantial progress that states have made in regulating disposal of fossil fuel combustion wastes in surface impoundments and landfills in recent years, as well as the active role that this industry has played recently in facilitating responsible waste disposal practices, EPA believes that subtitle D controls will provide sufficient clarity and incentive for states to close the remaining gaps in coverage, and for facilities to ensure that their wastes are managed properly.

For minefilling, although we have considerable concern about certain current practices (*e.g.,* placement directly into groundwater), we have not yet identified a case where placement of coal wastes can be determined to have actually caused increased damage to ground water. In addition, there is a federal regulatory program—SMCRA—expressly designed to address environmental risks associated with coal mines. Finally, given that states have been diligent in expanding and upgrading programs for surface impoundments and landfills, we believe they will be similarly responsive in addressing environmental concerns arising from this emerging practice. In short, we arrive at the same conclusions, for substantially the same reasons, for this practice as we did for landfills and surface impoundments: that subtitle D controls, or upgraded SMCRA controls or a combination of the two, should provide sufficient clarity and incentive to ensure proper handling of this waste when minefilled. Having determined that subtitle C regulation is not warranted for all other management practices, EPA does not see a basis in the record for carving this one practice out for separate regulatory treatment.

Once these subtitle D regulations are effective, facilities would be subject to citizen suits for any violation of the standards. If EPA were addressing wastes that had not been addressed by the states (or the federal government) in the past, or an industry with wide evidence of irresponsible solid waste management practices, EPA may well conclude that the additional incentives for improvement and compliance provided by the subtitle C scheme—the threat of federal enforcement and the stigma associated with improper management of RCRA subtitle C waste—were necessary. But the record before us indicates that the structure and the sanctions associated with a subtitle D approach (or a SMCRA approach if EPA determines it is equivalent) should be sufficient.

We also see a potential downside to pursuing a subtitle C approach. Section 8002(n)(8) directs us to consider, among other factors, "the current and potential utilization of such materials." Industry commenters have indicated that they believe subjecting any coal combustion wastes to a subtitle C regime would place a significant stigma on these wastes, the most important effect being that it would adversely impact beneficial reuse. As we understand it, the concern is that, even though beneficially reused waste would not be hazardous under the contemplated subtitle C approach, the link to subtitle C would nonetheless tend to discourage purchase and re-use of the wastes or products made from the wastes. We do not wish to place any unnecessary barriers on the beneficial uses of these wastes, because they conserve natural resources, reduce disposal costs and reduce the total amount of waste destined for disposal. States and industry have also expressed concern that regulation under subtitle C could cause a halt in the use of coal combustion wastes to reclaim abandoned and active mine sites. If this were to occur, it would be unfortunate in that when done properly, we recognize this practice can lead to substantial environmental benefits. EPA believes the contingent management scheme we discussed should diminish any stigma that might be associated with the subtitle C link. Nonetheless, we acknowledge the possibility that the approach could have unintended consequences. We would be particularly concerned about any adverse effect on the beneficial re-use market for these wastes because more than 23 percent (approximately 28 million tons) of the total coal combustion waste generated each year is beneficially reused and an additional eight percent (nine million tons) is used for minefilling. EPA believes that such reuse when performed properly, is by far the environmentally preferable destination for these wastes, including when minefilled. Normally, concerns about stigma are not a deciding factor in EPA's decisions under RCRA, given the central concern under the statute for protection of human health and the environment. However, given our conclusion that the subtitle D approach here should be fully effective in protecting human health and the environment, and given the large and salutary role that beneficial reuse plays for this waste, concern over stigma is a factor supporting our decision today that subtitle C regulation is unwarranted in light of our decision to pursue a subtitle D approach.

As we proceed with regulation development, we will also take enforcement action under RCRA section 7003 when we identify cases of imminent and substantial endangerment. We will also use Superfund remedial and emergency response authorities under the Comprehensive Environmental Response Compensation and Liabilities Act (CERCLA), as appropriate, to address damages that result in risk to human health and the environment. We will also take into account new information as it becomes available. We are awaiting a National Academy of Sciences report scheduled to be released in June 2000. This report will present a comprehensive review of mercury and recommendations on appropriate adverse health effects levels for this constituent. We believe that this report will enhance our understanding of the risks due to exposure to mercury, and we will review and assess its implications for today's decision on fossil fuel combustion wastes. These efforts may result in a re-evaluation of the risks posed by managing coal combustion wastes.

3. What Is the Basis for EPA's Regulatory Determination for Oil Combustion Wastes?

A. What Is the Agency's Decision Regarding the Regulatory Status of Oil Combustion Wastes and Why Did EPA Make This Decision?

We have determined that it is not appropriate to issue regulations under subtitle C of RCRA applicable to oil combustion wastes because: (a) We have not identified any beneficial uses that are likely to present significant risks to human health or the environment; and (b) except for a limited number of unlined surface impoundments, we have not identified any significant risks to human health and the environment associated with any waste management practices.

We intend to work with the State of Massachusetts and the owners and operators of the remaining two oil combustion facilities that currently manage their wastes in unlined surface impoundments to ensure that their wastes are managed in a manner that protects human health and the environment.

B. What Were EPA's Tentative Decisions as Presented in the Report to Congress and Why Did EPA Make That Decision?

In the Report to Congress, we stated that the only management scenario for which we found risks posed by management of oil combustion wastes was when oil combustion wastes are managed in unlined surface impoundments. The Report to Congress further explained that we were considering two approaches to address these identified risks. One approach was to regulate using RCRA subtitle C authority. The other approach was to encourage voluntary changes so that no oil combustion wastes are managed in unlined surface impoundments. This voluntary approach is based on recent industry and state regulatory trends to line oil combustion waste disposal units and implement groundwater monitoring.

We also tentatively decided that the existing beneficial uses of oil combustion wastes should remain exempt from RCRA subtitle C. There are few existing beneficial uses of these wastes, which include use in concrete products, structural fill, roadbed fill, and vanadium recovery. We determined that no significant risks to human health exist for the beneficial uses of these wastes. For the case of facilities that accept these wastes to recover vanadium from them, we explained that if the wastes resulting from the metal recovery processes are hazardous, they will be subject to existing hazardous waste requirements.

We found in most cases that OCW, whether managed alone or co-managed, are rarely characteristically hazardous. Additionally, we identified no significant ecological risks posed by land disposal of OCW. We identified only one documented damage case involving OCW in combination with coal combustion wastes, and it did not affect human receptors.

Although most of the disposed oil combustion wastes are managed in lined surface impoundments, we did identify six utility sites where wastes are managed in unlined units. We expressed particular concern with management of these wastes in unlined settling basins and impoundments that are designed and operated to discharge the aqueous portion of the wastes to ground water. Our risk analysis indicated that, in these situations, three metals—arsenic, nickel, and vanadium—may pose potential risk by the groundwater pathway.

C. How Did Commenters React to EPA's Tentative Decisions and What Was EPA's Analysis of Their Comments?

Because we were able to identify so few unlined surface impoundments, the only management scenario for which we found risks, the primary focus of the comments regarding oil combustion wastes was on the six unlined surface impoundments that we identified. In addition, there were extensive comments on our modeling and risk assessment methodology for the groundwater pathway that are applicable to our assessment of risks posed by oil combustion wastes.

1. How Did Commenters React to the Six Unlined Oil Combustion Waste Surface Impoundments That We Identified?

Comments. Industry commenters supported the approach to encourage voluntary changes in industry practices on a site-specific basis, and explained why they believed hazardous waste regulations are unnecessary. The environmental community supported the development of hazardous waste regulations.

EPA's Analysis of Comments. In the RTC, we identified that our only concern about oil combustion wastes was based on the potential for migration of arsenic, nickel, and vanadium from unlined surface impoundments. We requested information on this issue and did not receive any additional data and/or information to refute our tentative finding stated in the RTC that these unlined surface impoundments could pose a significant risk.

As stated in the RTC, there are only six sites involving two companies that have unlined surface impoundments. Four of the sites are in Florida and are operated by one company. The company operating the four unlined impoundments in Florida is undertaking projects to mitigate potential risks posed by their unlined management units. At a May 21, 1999 public hearing, the company announced its plans to remove all the oil ash and basin material from its unlined impoundments and to line or close the units. The company informed us in January 2000 that it had completed the lining of all the units. Based on this information, we do not believe that these units pose a significant risk to human health and the environment.

The other two sites with unlined impoundments are operated by one utility in Massachusetts. Both sites are permitted under Massachusetts' ground water discharge permit program and have monitoring wells around the unlined basins. Arsenic is monitored for compliance with state regulations. Although the company expressed no plans to line their impoundments, they are preparing to implement monitoring for nickel and vanadium in ground water around the waste management units. We have been working with the State and the company to obtain additional information to evaluate these two management units. We will continue this effort and will work with the company and the State to ensure that any necessary measures are taken so that these wastes are managed in a manner that protects human health and the environment.

2. How Did Commenters React to the Groundwater Modeling and Risk Assessment Analyses Conducted by EPA to Support Its Findings in the Report to Congress?

Comments. Industry and public interest group commenters submitted detailed critiques of the ground water model, EPACMTP, that we used for our risk analysis. Industry commenters believe that the model will overestimate the levels of contaminants that may migrate down-gradient from disposed wastes. Environmental groups expressed the opposite belief; that is, that the model underestimates down-gradient chemical concentrations and, therefore, underestimates the potential risk posed by oil combustion wastes.

EPA's Analysis of the Comments. We are carefully reviewing all of the comments on the model and have determined that the process of thoroughly investigating all of the comments will take substantially more time to complete than is available within the court deadline for issuing this regulatory determination. At this time, we are uncertain of the overall outcome of our analysis of the issues raised in the comments. Accordingly, we have decided not to use the results of our ground water pathway risk analysis in support of today's regulatory determination on fossil fuel combustion wastes. As explained above, we believe that actions have been taken or are under way by specific companies and/or the State of Massachusetts to address potential risks at the six impoundments that we have been able to identify. Therefore we believe that further groundwater analysis is unnecessary at this time.

Meanwhile, we will continue with our analysis of comments on the groundwater model and risk analysis. This may involve changing or restructuring various aspects of the model, if appropriate. It may also include additional analyses to determine whether any changes to the model or modeling methodology would materially affect the groundwater risk analysis results that were reported in the RTC. If our investigations reveal that a reanalysis of groundwater risks is appropriate, we will conduct the analysis and reevaluate today's decisions as appropriate.

In addition to our ongoing review of comments on the groundwater model, one element of the model—the metals partitioning component called "MINTEQ"—has been proposed for additional peer review. When this additional peer review is completed, we will take the findings and recommendations into account in any overall decision to re-evaluate today's regulatory determination.

D. What Is the Basis for Today's Decisions?

We have determined that it is not appropriate to establish national regulations applicable to oil combustion wastes because: (a) We have not identified any beneficial uses that are likely to present significant risks to human health or the environment; and (b) except for two remaining unlined surface impoundments, we have not identified any significant risks to human health and the environment associated with any waste management practices. As explained in the previous section, we intend to work with the State of Massachusetts and the owners and operators of the remaining two oil combustion facilities that currently manage their wastes in unlined surface impoundments to ensure that any necessary measures are taken so that their wastes are managed in a manner that protects human health and the environment. Given the limited number of sites at issue and our ability to adequately address risks from these waste management units through site-specific response measures, we see no need for issuing regulations under subtitle C or D of RCRA.

4. What Is the Basis for EPA's Regulatory Determination for Natural Gas Combustion Wastes?

A. What Is the Decision Regarding the Regulatory Status of Natural Gas Combustion Wastes?

For the reasons described in the Report to Congress (pages 7–1 to 7–3), EPA has decided that regulation of natural gas combustion wastes as hazardous wastes under RCRA subtitle C or D is not warranted. The burning of natural gas generates virtually no solid waste.

B. What Was EPA's Tentative Decision as Presented in the Report to Congress?

The Agency's tentative decision was to retain the subtitle C exemption for natural gas combustion because virtually no solid waste is generated.

C. How Did Commenters React to EPA's Tentative Decision?

No commenters on the RTC disagreed with EPA's findings or its tentative decision to continue the exemption for natural gas combustion wastes.

Specific comments on this issue supported our tentative decision to retain the exemption for natural gas combustion waste. One industry association encouraged us to foster the use of natural gas as a substitute for other fossil fuels. While some public interest group commenters disagreed broadly with our tentative conclusions to retain the exemption for fossil fuel combustion wastes, they did not specifically address natural gas combustion wastes.

D. What Is the Basis for Today's Decision?

The burning of natural gas generates virtually no solid waste. We, therefore, believe that there is no basis for EPA developing subtitle C or D regulations applicable to natural gas combustion wastes.

5. What Is the History of EPA's Regulatory Determinations for Fossil Fuel Combustion Wastes?

A. On What Basis Is EPA Required To Make Regulatory Determinations Regarding the Regulatory Status of Fossil Fuel Combustion Wastes?

Section 3001(b)(3)(C) of the Resource Conservation and Recovery Act (RCRA) as amended requires that, after completing a Report to Congress mandated by section 8002(n) of RCRA, the EPA Administrator must determine whether Subtitle C (hazardous waste) regulation of fossil fuel combustion wastes is warranted.

B. What Was EPA's General Approach in Making These Regulatory Determinations?

We began our effort to make our determination of the regulatory status of fossil fuel combustion wastes by studying high volume coal combustion wastes managed separately from other fossil fuel combustion wastes that are generated by electric utilities. In February 1988, EPA published the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report addressed four large-volume coal combustion wastes generated by electric utilities and independent power producers when managed alone. The four wastes are fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) wastes. The report did not address co-managed utility coal combustion wastes (UCCWs), other fossil fuel wastes generated by utilities, or wastes from non-utility boilers burning any type of fossil fuel. Because of other priorities at the time, we did not immediately complete a determination of the regulatory status of these large-volume coal combustion wastes.

C. What Happened When EPA Failed To Issue Its Determination of the Regulatory Status of the Large Volume Utility Combustion Wastes in a Timely Manner?

In 1991, a suit was filed against EPA for not completing a regulatory determination on fossil fuel combustion wastes (*Gearhart* v. *Reilly,* Civil No. 91–2345 (D.D.C.)). On June 30, 1992, the Agency entered into a Consent Decree that established a schedule for us to complete the regulatory determination for all fossil fuel combustion wastes in two phases:

• The first phase covers fly ash, bottom ash, boiler slag, and flue gas emission control wastes from the combustion of coal by electric utilities and independent commercial power producers. These are the four large volume wastes that were the subject of the 1988 Report to Congress described above. We refer to this as the Part 1 regulatory determination.

• The second phase covers all of the "remaining" fossil fuel combustion wastes not covered in the Part 1 regulatory determination. We refer to this as the Part 2 regulatory determination, which is the subject of today's action. Under the current court-order, EPA was directed to issue the Part 2 regulatory determination by April 25, 2000.

D. When Was the Part 1 Regulatory Decision Made and What Were EPA's Findings?

In 1993, EPA issued the Part 1 regulatory determination, in which we retained the exemption for Part 1 wastes (see 58 FR 42466; August 9, 1993). The four Part 1 large-volume utility coal combustion wastes (UCCWs) are also addressed in the Part 2 regulatory determination when they are co-managed with low-volume fossil fuel combustion wastes not covered in the Part 1 determination.

6. Executive Orders and Laws Addressed in Today's Action

A. Executive Order 12866—Determination of Significance

Under Executive Order 12866, (58 FR 51735, Oct. 4, 1993) we must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

• Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

• Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

• Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

• Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles in the Executive Order."

Under Executive Order 12866, this is a "significant regulatory action." Thus, we have submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations are documented in the public record.

B. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

Today's action is not subject to the RFA, which generally requires an agency to prepare a regulatory flexibility analysis for any rule that will have a significant economic impact on a substantial number of small entities. The RFA applies only to rules subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act (APA) or any other statute. This action is not subject to notice and comment requirements under the APA or any other statute. Today's action is being taken pursuant to section 3001(b)(3)(C) of the Resource Conservation and Recovery Act. This provision requires EPA to make a determination whether to regulate fossil fuel combustion wastes after submission of its Report to Congress and public hearings and an opportunity for comment. This provision does not require the publication of a notice of proposed rulemaking and today's action is not a regulation. *See American Portland Cement Alliance* v. *E.P.A.,* 101 F.3d 772 (D.C.Cir. 1996).

C. Paperwork Reduction Act Information Collection Requests

Today's final action contains no information collection requirements.

D. Unfunded Mandates Reform Act

Today's action is not subject to the requirements of sections 202 and 205 of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4. Title II of UMRA establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year.

Before we issue a rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the rule's objectives. Section 205 doesn't apply when it is inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the final rule explains why that alternative was not adopted. Before we establish any regulatory requirements that may significantly affect small governments, including tribal governments, we must have developed under section 203 of the UMRA a small-government-agency plan. The plan must provide for notifying potentially affected small governments, enabling them to have meaningful and timely input in the developing EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Today's final action contains no federal mandates (under the regulatory provisions of Title II of the UMRA) for state, local, or tribal governments or the private sector. Today's final action imposes no enforceable duty on any state, local or tribal governments or the private sector.

In addition, we have determined this action contains no federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled Federalism (64 FR 43255, August 10, 1999) requires us to develop an accountable process to ensure meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications. The executive order defines policies that have federalism implications to include regulations that have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

Under section 6 of Executive Order 13132, we may issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that isn't required by statute, only if the federal government provides funds the direct compliance costs incurred by state and local governments, or if EPA consults with state and local officials early in the development of the proposed regulation. Also, EPA may issue a regulation that has federalism implications and that preempts state law, only if we consult with state and local officials early in the development of the proposed regulation.

If EPA complies by consulting, Executive Order 13132 requires us to provide OMB, in a separately identified section of the rule's preamble, a federalism summary impact statement (FSIS). The FSIS must describe the extent of our prior consultation with state and local officials, summarizing the nature of their concerns and our position supporting the need for the regulation, and state the extent to which the concerns of state and local officials have been met. Also, when we transmit a draft final rule with federalism implications to OMB for review under Executive Order 12866, our federalism official must include a certification that EPA has met the requirements of Executive Order 13132 in a meaningful and timely manner.

Today's final action does not have federalism implications. It will not have a substantial direct affect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This is because no requirements are imposed by today's action, and EPA is not otherwise mandating any state or local government actions. Thus, the requirements of section 6 of the Executive Order do not apply to this final action.

F. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, EPA may take an action that isn't required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, only if the federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires us to describe in a separately identified section of the preamble to the rule the extent of our prior consultation with representatives of affected tribal governments, summarizing of the nature of their concerns, and state the need for the regulation. Also, Executive Order 13084 requires EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments "to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities."

Today's final action does not significantly or uniquely affect the communities of Indian tribal governments. This is because today's action by EPA involves no regulations or other requirements that significantly or uniquely affect Indian tribal governments. So, the requirements of section 3(b) of Executive Order 13084 do not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

"Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, we must evaluate the environmental health or safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

Today's final action isn't subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because we have no reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. Risks were thoroughly evaluated during the course of developing today's decision and were determined not to disproportionately affect children.

H. National Technology Transfer and Advancement Act of 1995

As noted in the proposed rule, section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law. No. 104–113, section12(d) (15 U.S.C. 272 note) directs EPA to use voluntary-consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary-consensus standards are technical standards (such as materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary-consensus standards bodies. The NTTAA directs us to explain to Congress, through OMB, when we decide not to use available and applicable voluntary-consensus standards.

Today's final action involves no technical standards. So, EPA didn't consider using any voluntary-consensus standards.

I. Executive Order 12898: Environmental Justice

EPA is committed to addressing environmental justice concerns and is assuming a leadership role in environmental justice initiatives to enhance environmental quality for all populations in the United States. The Agency's goals are to ensure that no segment of the population, regardless of race, color, national origin, or income bears disproportionately high and adverse human health or environmental impacts as a result of EPA's policies, programs, and activities, and that all people live in safe and healthful environments. In response to Executive Order 12898 and to concerns voiced by many groups outside the Agency, EPA's Office of Solid Waste and Emergency Response formed an Environmental Justice Task Force to analyze the array of environmental justice issues specific to waste programs and to develop an overall strategy to identify and address these issues (OSWER Directive No. 9200.317).

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, does not apply because this action is not a rule for purposes of 5 U.S.C. 804(3). Rather, this action is an order as defined by 5 U.S.C. 551(6).

7. How To Obtain More Information

Documents related to this regulatory determination, including EPA's response to the public comments, are available for inspection in the docket. The relevant docket numbers are: F–99–FF2D–FFFFF for the regulatory determination, and F–99–FF2P–FFFFF for the RTC. The RCRA Docket Information Center (RIC), is located at Crystal Gateway I, First Floor, 1235 Jefferson Davis Highway, Arlington, VA. The RIC is open from 9 a.m. to 4 p.m., Monday through Friday, excluding Federal holidays. To review docket materials, it is recommended that the public make an appointment by calling 703-603–9230. The public may copy a maximum of 100 pages from any regulatory docket at no charge. Additional copies cost $0.15/page. The index and some supporting materials are available electronically. See the Supplementary Information section for information on accessing them.

List of Subjects in 40 CFR Part 261

Fossil fuel combustion waste, Coal combustion, Gas combustion, Oil combustion, Special wastes, Bevill exemption

Dated: April 25, 2000.

Carol M. Browner,

Administrator.

[FR Doc. 00–11138 Filed 5–19–00; 8:45 am]

BILLING CODE 6560–50–U

Hart Exhibit 11
Docket No. E-7, Sub 1214

I/A

NCDENR

North Carolina Department of Environment and Natural Resources

Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

December 18, 2009

RECEIVED
JAN - 4 2010
EH & S

Mr. Allen Stowe
Water Management
Duke Energy Corporation
EC 13K / PO Box 1006
Charlotte, NC 28201-1006

Dear Mr. Stowe:

Over the past several months, the Division of Water Quality (DWQ) has been reviewing the data and maps submitted by Duke Energy on April 30, 2009. Based on the review of the submitted data, specific recommendations and additional information requests on a site-by-site basis are attached. These attachments are formatted so that they can be sent to each individual site with the appropriate contact information for any follow up actions. All information requested is due no later than February 28, 2010.

During this review period, there has been a clarification by the Attorney General's Office of how Corrective Action (15A NCAC 02L .0106) requirements apply to facilities permitted prior to December 30, 1983. It was determined that facilities exceeding groundwater standards, permitted under G.S. 143-215.1, and permitted prior to December 30, 1983, fall under 15A NCAC 02L .0106(c). This clarification gives Duke Energy the option to seek approval of a corrective action plan that does not require remediation to groundwater standards [15A NCAC 2L .0106 (k)] or may allow attenuation by natural processes [15A NCAC 2L .0106 (l)].

As a result of the Attorney General's clarification, DWQ is requesting that each facility place groundwater monitoring wells at the compliance boundary. Where appropriate, monitoring of groundwater discharges to surface water will be required. As permits are renewed, groundwater monitoring will be added to the updated permits, and similar parameters will be required to be monitored at each site.

In light of concerns brought up by your staff in past discussions, combining compliance boundaries for adjacent DWQ permitted activities will be allowed, as well as encouraged. We will also continue to work with other Divisions in DENR to determine options for combining compliance boundaries with adjacent non-DWQ permitted activities.

As this program progresses, we look forward to continue working with you. If you have any questions concerning the attached requests at any of your sites, please contact Debra Watts at (919) 715-6699 or Eric Smith at (919) 715-6196. Your prompt attention to these matters is appreciated.

Sincerely,

T. L. Bush

Ted L. Bush, Jr., Chief
Aquifer Protection Section

Attachments

cc: Coleen H. Sullins
Chuck Waklid
Jeff Poupart, NPDES
Andrew Pitner – Mooresville Regional Office APS
Sherry Knight – Winston-Salem Regional Office APS
Central Office Files

North Carolina Department of Environment and Natural Resources

Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

Attachment 1

Site Name: Allen Steam Station
County: Gaston County
Division of Water Quality Aquifer Protection Section Regional Office: Mooresville Regional Office (MRO)

Hydrogeology

- Based on the supplied maps, monitoring wells AB-4, AB-4D, AB-5, AB-6A, AB-6R, and AB-8 are located inside the Review/Compliance Boundaries. These wells are not suitable for determining compliance.
- Recommend a monitoring well be added near the southeast corner of the active ash basin at the Compliance Boundary. There appears to be a topographic draw that extends to the southeast away from the Active Ash Basin. This could be a conduit for groundwater to flow toward Lake Wylie from the Active Ash Basin.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the MRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The MRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.
- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (µg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

One North Carolina Naturally

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
  - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
  - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and
  - Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
  - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.
- Additional questions relating to previous submittal:
  - Monitoring wells AB-2 and AB-2D are located outside of the Compliance Boundary and are adjacent to a non-DWQ permitted ash storage area. What is their relevance to the NPDES permit?
  - Are the Structural Fill areas part of a DWQ permit?

Contacts

DWQ APS Central Office Mailing Address: 1636 Mail Service Center
Raleigh, North Carolina 27699-1636

DWQ APS Central Office Staff:

Debra Watts
APS Groundwater Protection Unit Supervisor
debra.watts@ncdenr.gov
(919) 715-6699

Betty Wilcox
Environmental Chemist
betty.wilcox@ncdenr.gov
(919) 715-6169

Eric G. Smith, P.G.
Hydrogeologist
eric.g.smith@ncdenr.gov
(919) 715-6196

DWQ APS MRO Mailing Address: 610 East Center Avenue
Mooresville, North Carolina 28115

DWQ APS MRO Staff:

Andrew Pitner
APS Supervisor
andrew.pitner@ncdenr.gov
(704) 663-1699

NCDENR

North Carolina Department of Environment and Natural Resources

Division of Water Quality

Beverly Eaves Perdue Governor	Coleen H. Sullins Director	Dee Freeman Secretary

Attachment 2

Site Name: Buck Steam Station
County: Rowan County
Division of Water Quality Aquifer Protection Section Regional Office: Mooresville Regional Office (MRO)

Hydrogeology

- Based on the supplied maps, monitoring wells MW-1S, MW-1D, MW-3S, MW-3D, MW-4S, and MW-4D are at the edge of the waste boundary. These wells are not suitable for determining compliance.
- Recommend a monitoring well be added at the Compliance Boundary in a direct line northwest from the current location at the waste boundary toward the on-site water supply well. This will allow you to see if any contamination is migrating toward the water supply well.
- Recommend a monitoring well be added approximately 750 feet east of the large cylindrical structure at the Compliance Boundary. According to the topographic data, there is a draw that extends to the north in this area. This could be a conduit for groundwater to flow toward the Yadkin River from the Active Ash Basin.
- Recommend a monitoring well be added to the south of the Active Ash Basin Primary Cell at the Compliance Boundary. This well should be between the houses on Dukeville Road and the Active Ash Boundary to demonstrate that groundwater contamination is not migrating toward the residential houses.
- Recommend monitoring well(s) be added at the Compliance Boundary between the Active Ash Basins and the houses along Leonard Road.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the MRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The MRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.

AQUIFER PROTECTION SECTION
1636 Mail Service Center, Raleigh, North Carolina 27699-1636
Location: 2728 Capital Boulevard, Raleigh, North Carolina 27604
Phone: 919-733-3221 \ FAX 1: 919-715-0588; FAX 2: 919-715-6048 \ Customer Service: 1-877-623-6748
Internet: www.ncwaterquality.org

- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (µg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
  - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
  - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and
  - Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
  - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.
- Additional questions relating to previous submittal:
  - Is the Site Water Well sampled and how often?
  - Portions of the property boundary extend into the Yadkin River. Is this the case?

Contacts

DWQ APS Central Office Mailing Address:	1636 Mail Service Center Raleigh, North Carolina 27699-1636
DWQ APS Central Office Staff:	Debra Watts APS Groundwater Protection Unit Supervisor debra.watts@ncdenr.gov (919) 715-6699 Betty Wilcox Environmental Chemist betty.wilcox@ncdenr.gov (919) 715-6169 Eric G. Smith, P.G. Hydrogeologist eric.g.smith@ncdenr.gov (919) 715-6196
DWQ APS MRO Mailing Address:	610 East Center Avenue Mooresville, North Carolina 28115
DWQ APS MRO Staff:	Andrew Pitner APS Supervisor andrew.pitner@ncdenr.gov (704) 663-1699

NCDENR
North Carolina Department of Environment and Natural Resources
Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

Attachment 3

Site Name: Cliffside Steam Station
County: Cleveland County
Division of Water Quality Aquifer Protection Section Regional Office: Mooresville Regional Office (MRO)

Hydrogeology

- Based on the supplied data, you labeled monitoring wells CLMW-2 and MW-2D as the background wells; however, based on submitted water level data, these wells should be downgradient wells.
- CLMW-6 is not a suitable for a background well due to its location at the Waste Boundary. Recommend that a new background well be added elsewhere on the property.
- Based on the supplied maps, monitoring wells CLMW-1, CLMW-2S, MW-2D, CLMW-3S, CLMW-3D, CLMW-5S, MW-8S, MW-8D, MW-11S, and MW-11D are located within the waste boundary. These wells are not suitable for determining compliance.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the MRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The MRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.
- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (µg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
  - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
  - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and
  - Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
  - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.
- Additional questions relating to previous submittal:
  - What is proposed or currently constructed on the barren areas shown on the submitted June 2007 aerial map?

Contacts

DWQ APS Central Office Mailing Address:	1636 Mail Service Center Raleigh, North Carolina 27699-1636
DWQ APS Central Office Staff:	Debra Watts APS Groundwater Protection Unit Supervisor debra.watts@ncdenr.gov (919) 715-6699
	Betty Wilcox Environmental Chemist betty.wilcox@ncdenr.gov (919) 715-6169
	Eric G. Smith, P.G. Hydrogeologist eric.g.smith@ncdenr.gov (919) 715-6196
DWQ APS MRO Mailing Address:	610 East Center Avenue Mooresville, North Carolina 28115
DWQ APS MRO Staff:	Andrew Pitner APS Supervisor andrew.pitner@ncdenr.gov (704) 663-1699

NCDENR
North Carolina Department of Environment and Natural Resources
Division of Water Quality

Beverly Eaves Perdue Governor	Coleen H. Sullins Director	Dee Freeman Secretary

Attachment 4

Site Name: Marshall Steam Station
County: Catawba County
Division of Water Quality Aquifer Protection Section Regional Office: Mooresville Regional Office (MRO)

Hydrogeology

- Based on the supplied maps, monitoring wells MW-7S, MW-7D, MW-8S, MW-8D, MW-9S, and MW-9D are located inside of the waste boundary. These wells are not suitable for determining compliance.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the MRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The MRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.
- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (µg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
  - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
  - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and

- Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
  - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.
- Additional questions relating to previous submittal:
  - On the supplied map, your Compliance Boundary extends around the Ash Landfill Permit 18-04 that is located just west of MW-6. This Ash Landfill is not under the NPDES permit. Is the Division of Waste Management in agreement with extending the Compliance Boundary around it?
  - The Waste Boundary crosses the property boundary near north boundary of active ash basin. Is this correct?
  - Are the Structural Fill areas part of a DWQ permit?
  - What are the rectangular-shaped structures near the middle of the Active Ash Basin that are not included in the waste boundary and what do they contain?

Contacts

DWQ APS Central Office Mailing Address:	1636 Mail Service Center Raleigh, North Carolina 27699-1636
DWQ APS Central Office Staff:	Debra Watts APS Groundwater Protection Unit Supervisor debra.watts@ncdenr.gov (919) 715-6699 Betty Wilcox Environmental Chemist betty.wilcox@ncdenr.gov (919) 715-6169 Eric G. Smith, P.G. Hydrogeologist eric.g.smith@ncdenr.gov (919) 715-6196
DWQ APS MRO Mailing Address:	610 East Center Avenue Mooresville, North Carolina 28115
DWQ APS MRO Staff:	Andrew Pitner APS Supervisor andrew.pitner@ncdenr.gov (704) 663-1699

NCDENR
North Carolina Department of Environment and Natural Resources
Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

Attachment 5

Site Name: Riverbend Steam Station
County: Gaston County
Division of Water Quality Aquifer Protection Section Regional Office: Mooresville Regional Office (MRO)

Hydrogeology

- Based on the supplied maps, monitoring wells WM-1S, WM-1D, WM-2S, WM-2D, WM-3S, WM-3D, WM-4S, WM-4D, WM-5S, WM-5D, WM-6S, and WM-6D are between the waste boundaries and the review boundaries. These wells are not suitable for determining compliance.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the MRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The MRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.
- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (μg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
    - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
    - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and
    - Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
    - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.

Contacts

DWQ APS Central Office Mailing Address:	1636 Mail Service Center Raleigh, North Carolina 27699-1636
DWQ APS Central Office Staff:	Debra Watts APS Groundwater Protection Unit Supervisor debra.watts@ncdenr.gov (919) 715-6699
	Betty Wilcox Environmental Chemist betty.wilcox@ncdenr.gov (919) 715-6169
	Eric G. Smith, P.G. Hydrogeologist eric.g.smith@ncdenr.gov (919) 715-6196
DWQ APS MRO Mailing Address:	610 East Center Avenue Mooresville, North Carolina 28115
DWQ APS MRO Staff:	Andrew Pitner APS Supervisor andrew.pitner@ncdenr.gov (704) 663-1699

NCDENR

North Carolina Department of Environment and Natural Resources

Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

Attachment 6

Site Name: Belews Creek Steam Station
County: Stokes County
Division of Water Quality Aquifer Protection Section Regional Office: Winston-Salem Regional Office (WSRO)

Hydrogeology

- Based on the supplied maps, monitoring wells MW-101S, MW-101D, MW-102S, and MW-102D are at the waste boundary. Based on their location, these wells are not suitable for determining compliance.
- Recommend a monitoring well be added directly west of monitoring well MW-104S on the western side of the Active Ash Basin at the Compliance/Property Boundary. There appears to be a topographic draw that extends southwest toward a pond. This could be a conduit for groundwater to flow toward the pond from the Active Ash Basin.
- MW-104S and MW-104D are not suitable background wells due to their location within the Compliance Boundary. Recommend that a new background well be added elsewhere on the property.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the WSRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The WSRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.
- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (μg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
    - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
    - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and
    - Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
    - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.
- Additional questions relating to previous submittal:
    - On the supplied maps, you show the Compliance Boundary for the Active Ash Basin being combined and extending around the Pine Hall Road Ash Landfill. This Ash Landfill is not under the NPDES permit. Is the Division of Waste Management in agreement with combining and extending the compliance boundaries? If not, make sure that the Compliance Boundary is the proper distance from the Active Ash Basin waste boundary only.
    - Based on other aerial photography, there appears to be several earthen structures which resemble ash ponds, structural fills, or landfills on your property southeast, south, and southwest of the steam plant along State Route 2042 which are not included on the supplied maps due to their scale. What are these structures?
    - Are the Structural Fill areas part of a DWQ permit?
    - What are the rectangular-shaped earthen structures located near the northern intersection of Duke Power Steam Plant Road and Pine Hall Road.

Contacts

DWQ APS Central Office Mailing Address:	1636 Mail Service Center Raleigh, North Carolina 27699-1636
DWQ APS Central Office Staff:	Debra Watts APS Groundwater Protection Unit Supervisor debra.watts@ncdenr.gov (919) 715-6699
	Betty Wilcox Environmental Chemist betty.wilcox@ncdenr.gov (919) 715-6169
	Eric G. Smith, P.G. Hydrogeologist eric.g.smith@ncdenr.gov (919) 715-6196
DWQ APS WSRO Mailing Address:	585 Waughtown Street Winston-Salem, North Carolina 27107
DWQ APS WSRO Staff:	Sherri Knight APS Supervisor sherri.knight@ncdenr.gov (336) 771-5000

North Carolina Department of Environment and Natural Resources
Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

Attachment 7

Site Name: Dan River Steam Station
County: Rockingham County
Division of Water Quality Aquifer Protection Section Regional Office: Winston-Salem Regional Office (WSRO)

Hydrogeology

- Based on the supplied data shallow monitoring well MW-12 has a water table above the screen.
- Based on the supplied maps, monitoring wells MW-9S, MW-9D, MW-10S, MW-10D, MW-11S, and MW-11D are located within the waste boundary. These wells are not suitable for determining compliance.
- Recommend that you extend your Review/Compliance Boundaries around the Ash Storage areas. This would make the MW-12 and MW-12D fall within the Compliance Boundary. Recommend that a new background well be added elsewhere on the property.
- Based on a clarification of the 15A NCAC 02L rules, monitoring wells are now required to be located at the Compliance Boundary. The proposed locations of these wells must be shown on the requested maps. Construction of these monitoring wells may begin after approval from the WSRO.
- Where constructing wells at the Compliance Boundary may not be feasible due to the proximity of surface water, groundwater seepage monitoring will be required. The proposed locations of these monitoring points must be shown on the requested maps. The WSRO will approve the final locations of the monitoring points.
- Combining Compliance Boundaries around any adjacent Division of Water Quality (DWQ) permitted activities is acceptable as well as recommended.
- Compliance Boundaries must not cross your property boundaries.

Groundwater Sampling and Data

- Please make sure that you sample the monitoring wells for the following constituents during each sampling event:

Aluminum	**Boron**	**Cobalt**	**Manganese**	**Potassium**	**Thallium**
Antimony	**Cadmium**	**Copper**	**Mercury**	**Selenium**	**TDS**
Arsenic	**Calcium**	**Iron**	**Nickel**	**Silver**	**Vanadium**
Barium	**Chloride**	**Lead**	**Nitrate**	**Sodium**	**Zinc**
Beryllium	**Chromium**	**Magnesium**	**pH (field)**	**Sulfate**	

- The listed parameters are intended to monitor constituents from the coal ash; additional parameters may be necessary to address contributions to the ash ponds from any other waste sources.
- All of the requested groundwater sampling parameters should be instituted starting with the next sampling round after receiving this letter.
- Please send the groundwater sampling data in both electronic (Microsoft Excel) and hardcopy forms.
- Please report all metals in micrograms per liter (µg/L) with the exception of Copper and Zinc which should be reported in milligrams per liter (mg/L) in accordance with the 15A NCAC 02L standard changes effective 1/1/10.
- The Aquifer Protection Section (APS) may allow some groundwater sampling parameters to be deleted based on non-detects over several sampling rounds or historical data provided.

Additional Information Requested

- Please submit the following updates to the maps by February 28, 2010:
  - Locations of proposed monitoring wells and/or groundwater seepage monitoring points,
  - Locations of all on-site inactive ash ponds and ash storage areas not previously identified, and
  - Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated Compliance Boundaries and monitoring wells,
- For the updated maps: Submit one (1) electronic copy and two (2) hard copies to the DWQ APS Central Office, and one (1) electronic copy and two (2) hard copies to the DWQ APS Regional Office.
  - Updates to the map can be made on the same aerial photo base as in the previous submittal. Please include the elevation contours.

Contacts

DWQ APS Central Office Mailing Address:	1636 Mail Service Center Raleigh, North Carolina 27699-1636
DWQ APS Central Office Staff:	Debra Watts APS Groundwater Protection Unit Supervisor debra.watts@ncdenr.gov (919) 715-6699
	Betty Wilcox Environmental Chemist betty.wilcox@ncdenr.gov (919) 715-6169
	Eric G. Smith, P.G. Hydrogeologist eric.g.smith@ncdenr.gov (919) 715-6196
DWQ APS WSRO Mailing Address:	585 Waughtown Street Winston-Salem, North Carolina 27107
DWQ APS WSRO Staff:	Sherri Knight APS Supervisor sherri.knight@ncdenr.gov (336) 771-5000

Duke Energy Progress
Docket No. E-2, Sub 1219
Estimated Rate Impacts of the deferral

GIP Exhibit 1 – Deferral Granted
Page 1

For Illustrative purposes only.

Dollars in thousands

		Years 1-5		Years 6-10	
	2018 Present Revenue Annualized	Annual Revenue Requirement	% Increase in Avg. Bill	Annual Revenue Requirement	% Decrease in Avg Bill from Year 5
Residential	1,879,740	116,711	6.2%	71,546	-2.3%
Small General Service	238,187	14,085	5.9%	8,635	-2.2%
Medium General Service	959,944	24,211	2.5%	14,933	-0.9%
Large General Service	575,133	9,166	1.6%	5,681	-0.6%
Seasonal & Intermittent	5,859	422	7.2%	258	-2.6%
Traffic Signal Service	563	35	6.2%	21	-2.3%
Outdoor lighting	92,941	4,062	4.4%	2,483	-1.6%
Total	3,752,367	168,692	4.5%	103,558	-1.7%

Rates assume the deferral is amortized over 5 years and removed deferral from revenue beginning in year 6.

Duke Energy Progress
Docket No. E-2, Sub 1219
10 Year Impact
Dollars in thousands

GIP Exhibit 1 – Deferral Granted
Page 2

Total NC Retail

Line No.	Description	Reference	2023	New Rates Effective 2024	2025	2026	2027	2028	New Rates Effective 2029	2030	2031	2032
1												
2												
3	Electric operating revenue	Revenue Requirement		168,692	168,692	168,692	168,692	168,692	103,558	103,558	103,558	103,558
4												
5	Electric operating expenses:											
6	Operation and maintenance											
7	Fuel used in electric generation											
8	Regulatory Fee	(Revenue * Reg Fee rate)		219	219	219	219	219	134	134	134	134
9	Uncollectibles	(Revenue * Uncollectible rate)		404	404	404	404	404	248	248	248	248
10	Depreciation and amortization	Revenue Requirement	31,625	31,625	31,625	31,625	31,625	31,625	31,625	31,625	31,625	31,625
11	Amortization of Deferral	Revenue Requirement		64,894	64,894	64,894	64,894	64,894				
12	Deferral	Deferral until new rates	(31,628)									
13	General taxes	Revenue Requirement	3	3	3	3	3	3	3	3	3	3
14	Interest on customer deposits		-	-	-	-	-	-	-	-	-	-
15	Income taxes	Calculated	-	16,577	16,577	16,577	16,577	16,577	16,577	16,577	16,577	16,577
16	Amortization of investment tax credit		-	-	-	-	-	-	-	-	-	-
17												
18	Total electric operating expenses	Sum L8 through L15	0	113,722	113,722	113,722	113,722	113,722	48,588	48,588	48,588	48,588
19												
20	Operating income	L3- L18	$ (0)	54,970	54,970	54,970	54,970	54,970	54,970	54,970	54,970	54,970
21												
22	Notes:											
23	Revenue: positive number increases revenue / negative number decreases revenue											
24	Expense: positive number increases expense / negative number decreases expense											
25												
26												
27	**Rate Base Line Items**											
28												
29	Electric plant in service		$ 824,932	$ 824,932	$ 824,932	$ 824,932	$ 824,932	$ 824,932	$ 824,932	$ 824,932	$ 824,932	$ 824,932
30	Accumulated depreciation and amortization		(66,668)	(98,293)	(129,919)	(161,544)	(193,170)	(224,795)	(256,421)	(288,046)	(319,672)	(351,297)
31	Electric plant in service, net	Sum L29 through L30	758,264	726,638	695,013	663,387	631,762	600,136	568,511	536,885	505,260	473,634
32												

Duke Energy Progress
Docket No. E-2, Sub 1219
Revenue Requirement
For the test period ended December 31, 2022 - Plant Update Period through December 2022, New Rates January 2024

GIP Exhibit 1 – Deferral Granted
Page 3

Revenue Requirement ($ in thousands)

			NC Retail			
			Asset Balance		Accumulated Depreciation	Net
1	**Plant**		as of 12/31/2022		As of 12/31/2022	Plant
2	Distribution		531,319		(14,670)	516,649
3	Transmission		157,167		(3,766)	153,401
4	General Plant		136,446		(16,606)	119,839
5	Total		824,932		(35,042)	789,889
6						
7	WACC - Pre Tax		9.09%			
8	Capital Revenue Requirement (Net Plant * WACC)					
9	Distribution		46,971			
10	Transmission		13,946			
11	General Plant		10,895			
12	Total		71,812			
13						
14	**Impact to Income Statement Line Items**					
15	Depreciation and amortization:		Years 1-5		Years 6-10	
16	Distribution depreciation expense	$	12,433	$	12,433	
17	Transmission depreciation expense		3,505		3,505	
18	General Plant depreciation expense		15,688		15,688	
19	Impact to deprec. and amortization (Sum L16 through L18)	$	31,625	$	31,625	
20						
21	Amortization of 2022 deferral:					
22	Distribution depreciation expense	$	37,759			
23	Transmission depreciation expense		10,259			
24	General Plant depreciation expense		16,876			
25	Impact to deprec. and amortization (Sum L22 through L24)		64,894			
26						
27	General taxes:					
28	Property tax rate		0.36%			
29						
30	Property tax (December 2022 Plant Balance * Property tax rate)					
31	Distribution property tax expense	$	2	$	2	
32	Transmission property tax expense		1		1	
33	General Plant property tax expense		0		0	
34	Impact to general taxes (Sum L70 through L74)	$	3	$	3	
35						
36	Total Operating Expenses (Depreciation + Amortization + Property Taxes)					
37	Distribution	$	50,193	$	12,435	
38	Transmission		13,765		3,505	
39	General Plant		32,564		15,688	
40	Total income taxes	$	96,522	$	31,628	
41						
42	Taxes		23.17%		23.17%	
43	Distribution	$	(11,629)	$	(2,881)	
44	Transmission		(3,189)		(812)	
45	General Plant		(7,545)		(3,635)	
46	Total income statement impact	$	(22,364)	$	(7,328)	
47						
48	Income Statement Impact (Operating expenses + Taxes)					
49	Distribution	$	38,564	$	9,554	
50	Transmission		10,576		2,693	
51	General Plant		25,019		12,053	
52	Total income statement Requirement	$	74,159	$	24,300	
53						
54	Retention Factor		76.55%		76.55%	
55						
56	Total Revenue Requirement (Capital Revenue Requirement + Income Statement impact/ Retention factor)					
57	Distribution	$	97,350	$	59,452	
58	Transmission		27,762		17,465	
59	General Plant		43,580		26,642	
60	Total Revenue Requirement	$	168,692	$	103,558	
61						

Grid Deferral Assumptions

CWIP spend is spent evenly throughout the year

Timing of assets going in service
Distribution - Assumed 1 month delay from time of CWIP spend to asset placed in service.
Transmission - Assumed 6 month delay from time of CWIP spend to asset placed in service.
Communications - Assumed 3 month delay from time of CWIP spend to asset placed in service.
Advance DMS and Enterprise applications - assumed CWIP spend placed in service annually in December.

Depreciation rates
Distribution - applied a total distribution depreciation rate excluding meters.
Transmission - applied a total transmission rate
Communication - applied a total communications depreciation rate
Advanced DMS - assumed a 10 year asset life
Enterprise application - assumed a 5 year life

Returns
Assumed the weighted average cost of capital as reflected in the company's application.

O&M
Reflected estimated installation O&M expenses.
Assumed no incremental on going O&M expenses.
Assumed new depreciation rates effective 9/1/2020.

Property Taxes
Property taxes begin the next calendar year after the asset is placed in service.

Deferral
Assumed deferral begins 1/1/2020, and with assets placed in service beginning 3/1/2020.
Assumed plant additions stopped being eligible for deferral 1/1/2023.
Deferral of return, depreciation, property tax continued until 12/31/2023 on electric plant in service balances as of 12/31/2022.

Deferral recovery
Assumed a 5 year levelized amortization of the deferral.

Revenue Requirement
Assumes the test period was twelve months ended December 2022.
Assumed there was no additional update period after the test period.
Assumed rates were effective 1/1/2024.
Assumed rates were adjusted after the 5 year amortization of the deferral expired

Rate impacts
Allocations are based on 2018 cost of service study as presented in the current rate case.
For modeling purposes, forecasted distribution costs were allocated using a composite distribution plant allocator,
excluding extra facilities and FERC accounts 370, 371 and 373.
In actuals, distribution costs will be allocated more specifically based on the individual FERC accounts they are booked to.
Does not include any savings that might be realized in the base rate cases as a result of the investments.
Percent increases shown based on present revenues annualized with riders as presented in current case

DUKE ENERGY PROGRES
Docket No. E-2, Sub 1219
NORTH CAROLINA RETAIL GRID IMPROVEMENT PLAN
SUMMARY OF DEFERRAL

GIP Exhibit 1 – Deferral Granted
Page 5

DEP NC Grid Work Plan

Dollars in thousands (000s)	2020	2021	2022	2023
System CWIP Spend	275,836	408,479	507,192	
NC Retail CWIP Spend	208,643	302,061	394,784	
Cumulative In Service (Beg Mar 2020)	164,236	447,623	824,932	
Accum Depr	(1,712)	(12,451)	(35,042)	
Total Rate Base	162,523	435,173	789,889	
O&M (Beg Jan 2020)	4,729	7,207	9,880	
Depreciation (Beg Mar 2020)	1,712	10,738	22,592	31,625
Property Tax	-	596	1,623	2,991
Debt Return - Capital Asset	1,180	5,626	11,727	15,115
Debt Return - Deferred Balance	56	477	1,523	3,200
Equity Return - Capital Asset	4,293	20,473	42,674	55,000
Equity Return - Deferred Balance	204	1,737	5,540	11,644
Annual Deferral	12,174	46,854	95,559	119,576
Cumulative Deferral Balance	12,174	59,028	154,587	274,163

Duke Energy Progress
Docket No. E-2, Sub 1219
Estimated Rate Impacts of the deferral

GIP Exhibit 2 – Deferral Denied
Page 1

For Illustrative purposes only.

Dollars in thousands

	2018 Present Revenue Annualized	Years 1-10 Annual Revenue Requirement	Years 1-10 % Increase in Avg. Bill
Residential	1,879,740	14,588	0.8%
Small General Service	238,187	1,761	0.7%
Medium General Service	959,944	3,103	0.3%
Large General Service	575,133	1,198	0.2%
Seasonal & Intermittent	5,859	52	0.9%
Traffic Signal Service	563	4	0.8%
Outdoor lighting	92,941	512	0.6%
Total	3,752,367	21,219	0.6%

I/A

Duke Energy Progress
Docket No. E-2, Sub 1219
10 Year Impact
Dollars in thousands

GIP Exhibit 2 – Deferral Denied
Page 2

Total NC Retail

Line No.	Description	Reference	2023	New Rates Effective 2024	2025	2026	2027	2028	New Rates 2029	2030	2031	2032
1												
2												
3	Electric operating revenue	Revenue Requirement		21,219	21,219	21,219	21,219	21,219	21,219	21,219	21,219	21,219
4												
5	Electric operating expenses:											
6	Operation and maintenance											
7	Fuel used in electric generation											
8	Regulatory Fee	(Revenue * Reg Fee rate)		28	28	28	28	28	28	28	28	28
9	Uncollectibles	(Revenue * Uncollectible rate)		51	51	51	51	51	51	51	51	51
10	Depreciation and amortization	Revenue Requirement	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501	6,501
11	Amortization of Deferral	Revenue Requirement		-	-	-	-	-				
12	Deferral	Deferral until new rates										
13	General taxes	Revenue Requirement	1	1	1	1	1	1	1	1	1	1
14	Interest on customer deposits		-	-	-	-	-	-	-	-	-	-
15	Income taxes	Calculated	(1,506)	3,392	3,392	3,392	3,392	3,392	3,392	3,392	3,392	3,392
16	Amortization of investment tax credit		-	-	-	-	-	-	-	-	-	-
17												
18	Total electric operating expenses	Sum L8 through L15	4,995	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972
19												
20	Operating income	L3 - L18	$ (4,995)	11,247	11,247	11,247	11,247	11,247	11,247	11,247	11,247	11,247
21												
22	Notes:											
23	Revenue: positive number increases revenue / negative number decreases revenue											
24	Expense: positive number increases expense / negative number decreases expense											
25												
26												
27	**Rate Base Line Items**											
28												
29	Electric plant in service		$ 169,071	$ 169,071	$ 169,071	$ 169,071	$ 169,071	$ 169,071	$ 169,071	$ 169,071	$ 169,071	$ 169,071
30	Accumulated depreciation and amortization		(13,960)	(20,461)	(26,962)	(33,464)	(39,965)	(46,466)	(52,967)	(59,468)	(65,970)	(72,471)
31	Electric plant in service, net	Sum L29 through L30	155,111	148,609	142,108	135,607	129,106	122,605	116,103	109,602	103,101	96,600
32												

Duke Energy Progress
Docket No. E-2, Sub 1219
Revenue Requirement
For the test period ended December 31, 2022 - Plant Update Period through December 2022, New Rates January 2024

GIP Exhibit 2 – Deferral Denied
Page 3

Revenue Requirement ($ in thousands)

			NC Retail			
			Asset Balance		Accumulated Depreciation	Net
1	**Plant**		as of 12/31/2022		As of 12/31/2022	Plant
2	Distribution		106,264		(2,934)	103,330
3	Transmission		34,423		(925)	33,498
4	General Plant		28,383		(3,599)	24,784
5	Total		169,071		(7,459)	161,612
6						
7	WACC - Pre Tax		9.09%			
8	Capital Revenue Requirement (Net Plant * WACC)					
9	Distribution		9,394			
10	Transmission		3,045			
11	General Plant		2,253			
12	Total		14,693			
13						
14	**Impact to Income Statement Line Items**					
15	Depreciation and amortization:		Years 1-5		Years 6-10	
16	Distribution depreciation expense	$	2,487	$	2,487	
17	Transmission depreciation expense		768		768	
18	General Plant depreciation expense		3,247		3,247	
19	Impact to deprec. and amortization (Sum L16 through L18)	$	6,501	$	6,501	
20						
21	Amortization of 2022 deferral:					
22	Distribution depreciation expense					
23	Transmission depreciation expense					
24	General Plant depreciation expense					
25	Impact to deprec. and amortization (Sum L22 through L24)		-			
26						
27	General taxes:					
28	Property tax rate		0.36%			
29						
30	Property tax (December 2022 Plant Balance * Property tax rate)					
31	Distribution property tax expense	$	0	$	0	
32	Transmission property tax expense		0		0	
33	General Plant property tax expense		0		0	
34	Impact to general taxes (Sum L70 through L74)	$	1	$	1	
35						
36	Total Operating Expenses (Depreciation + Amortization + Property Taxes)					
37	Distribution	$	2,487	$	2,487	
38	Transmission		768		768	
39	General Plant		3,247		3,247	
40	Total income taxes	$	6,502	$	6,502	
41						
42	Taxes		23.17%		23.17%	
43	Distribution	$	(576)	$	(576)	
44	Transmission		(178)		(178)	
45	General Plant		(752)		(752)	
46	Total income statement impact	$	(1,506)	$	(1,506)	
47						
48	Income Statement Impact (Operating expenses + Taxes)					
49	Distribution	$	1,911	$	1,911	
50	Transmission		590		590	
51	General Plant		2,495		2,495	
52	Total income statement Requirement	$	4,995	$	4,995	
53						
54	Retention Factor		76.55%		76.55%	
55						
56	Total Revenue Requirement (Capital Revenue Requirement + Income Statement impact/ Retention factor)					
57	Distribution	$	11,890	$	11,890	
58	Transmission		3,816		3,816	
59	General Plant		5,512		5,512	
60	Total Revenue Requirement	$	21,219	$	21,219	
61						

Grid Deferral Assumptions

CWIP spend is spent evenly throughout the year
Assumed only 20% of original Grid plan would be spent without deferral.

Timing of assets going in service
Distribution - Assumed 1 month delay from time of CWIP spend to asset placed in service.
Transmission - Assumed 6 month delay from time of CWIP spend to asset placed in service.
Communications - Assumed 3 month delay from time of CWIP spend to asset placed in service.
Advance DMS and Enterprise applications - assumed CWIP spend placed in service annually in December.

Depreciation rates
Distribution - applied a total distribution depreciation rate excluding meters.
Transmission - applied a total transmission rate
Communication - applied a total communications depreciation rate
Advanced DMS - assumed a 10 year asset life
Enterprise application - assumed a 5 year life

Returns
Assumed the weighted average cost of capital as reflected in the company's application.

O&M
Reflected estimated installation O&M expenses.
Assumed no incremental on going O&M expenses.
Assumed new depreciation rates effective 9/1/2020.

Property Taxes
Property taxes begin the next calendar year after the asset is placed in service.

Deferral
Assumed no deferral

Revenue Requirement
Assumes the test period was twelve months ended December 2022.
Assumed there was no additional update period after the test period.
Assumed rates were effective 1/1/2024.

Rate impacts
Allocations are based on 2018 cost of service study as presented in the current rate case.
For modeling purposes, forecasted distribution costs were allocated using a composite distribution plant allocator, excluding extra facilities and FERC accounts 370, 371 and 373.
In actuals, distribution costs will be allocated more specifically based on the individual FERC accounts they are booked to.
Does not include any savings that might be realized in the base rate cases as a result of the investments.
Percent increases shown based on present revenues annualized with riders as presented in current case

DUKE ENERGY PROGRES
Docket No. E-2, Sub 1219
NORTH CAROLINA RETAIL GRID IMPROVEMENT PLAN
SUMMARY OF DEFERRAL

Not Applicable

Duke Energy Progress
Docket No. E-2, Sub 1219
Estimated Rate Impacts of the deferral

GIP Exhibit 3 – Deferral Granted (Settlement)
Page 1

For Illustrative purposes only.

Dollars in thousands

		Years 1-5		Years 6-10	
	2018 Present Revenue Annualized	Annual Revenue Requirement	% Increase in Avg. Bill	Annual Revenue Requirement	% Decrease in Avg Bill from Year 5
Residential	1,879,740	51,780	2.8%	32,478	-1.0%
Small General Service	238,187	6,221	2.6%	3,902	-0.9%
Medium General Service	959,944	8,255	0.9%	5,150	-0.3%
Large General Service	575,133	2,356	0.4%	1,458	-0.2%
Seasonal & Intermittent	5,859	202	3.4%	127	-1.2%
Traffic Signal Service	563	17	2.9%	10	-1.1%
Outdoor lighting	92,941	1,075	1.2%	630	-0.5%
Total	3,752,367	69,906	1.9%	43,755	-0.7%

Rates assume the deferral is amortized over 5 years and removed deferral from revenue beginning in year 6.

Duke Energy Progress
Docket No. E-2, Sub 1219
10 Year Impact
Dollars in thousands

GIP Exhibit 3 – Deferral Granted (Settlement)
Page 2

Total NC Retail

Line No.	Description	Reference	2023	New Rates Effective 2024	2025	2026	2027	2028	New Rates Effective 2029	2030	2031	2032
1												
2												
3	Electric operating revenue	Revenue Requirement		69,906	69,906	69,906	69,906	69,906	43,755	43,755	43,755	43,755
4												
5	Electric operating expenses:											
6	Operation and maintenance											
7	Fuel used in electric generation											
8	Regulatory Fee	(Revenue * Reg Fee rate)		91	91	91	91	91	57	57	57	57
9	Uncollectibles	(Revenue * Uncollectible rate)		167	167	167	167	167	105	105	105	105
10	Depreciation and amortization	Revenue Requirement	12,164	12,164	12,164	12,164	12,164	12,164	12,164	12,164	12,164	12,164
11	Amortization of Deferral	Revenue Requirement		26,054	26,054	26,054	26,054	26,054				
12	Deferral	Deferral until new rates	(12,165)									
13	General taxes	Revenue Requirement	1	1	1	1	1	1	1	1	1	1
14	Interest on customer deposits		-	-	-	-	-	-	-	-	-	-
15	Income taxes	Calculated	-	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282
16	Amortization of investment tax credit		-	-	-	-	-	-	-	-	-	-
17												
18	Total electric operating expenses	Sum L8 through L15	(0)	45,759	45,759	45,759	45,759	45,759	19,608	19,608	19,608	19,608
19												
20	Operating income	L3- L18	$ 0	24,147	24,147	24,147	24,147	24,147	24,147	24,147	24,147	24,147
21												
22	Notes:											
23	Revenue: positive number increases revenue / negative number decreases revenue											
24	Expense: positive number increases expense / negative number decreases expense											
25												
26												
27	**Rate Base Line Items**											
28												
29	Electric plant in service		$ 385,418	$ 385,418	$ 385,418	$ 385,418	$ 385,418	$ 385,418	$ 385,418	$ 385,418	$ 385,418	$ 385,418
30	Accumulated depreciation and amortization		(25,058)	(37,222)	(49,386)	(61,549)	(73,713)	(85,877)	(98,040)	(110,204)	(122,368)	(134,531)
31	Electric plant in service, net	Sum L29 through L30	360,360	348,196	336,033	323,869	311,705	299,542	287,378	275,214	263,051	250,887
32												

Duke Energy Progress
Docket No. E-2, Sub 1219
Revenue Requirement
For the test period ended December 31, 2022 - Plant Update Period through December 2022, New Rates January 2024

GIP Exhibit 3 – Deferral Granted (Settlement)
Page 3

Revenue Requirement ($ in thousands)

		NC Retail		
		Asset Balance	Accumulated Depreciation	Net
1	**Plant**	as of 12/31/2022	As of 12/31/2022	Plant
2	Distribution	340,904	(8,164)	332,740
3	Transmission	15,801	(418)	15,383
4	General Plant	28,714	(4,313)	24,400
5	Total	385,418	(12,895)	372,524
6				
7	WACC - Pre Tax	8.47%		
8	Capital Revenue Requirement (Net Plant * WACC)			
9	Distribution	28,176		
10	Transmission	1,303		
11	General Plant	2,066		
12	Total	31,545		
13				
14	**Impact to Income Statement Line Items**			
15	Depreciation and amortization:	Years 1-5	Years 6-10	
16	Distribution depreciation expense	$ 7,977	$ 7,977	
17	Transmission depreciation expense	352	352	
18	General Plant depreciation expense	3,834	3,834	
19	Impact to deprec. and amortization (Sum L16 through L18)	$ 12,164	$ 12,164	
20				
21	Amortization of 2022 deferral:			
22	Distribution depreciation expense	$ 20,705		
23	Transmission depreciation expense	996		
24	General Plant depreciation expense	4,353		
25	Impact to deprec. and amortization (Sum L22 through L24)	26,054		
26				
27	General taxes:			
28	Property tax rate	0.36%		
29				
30	Property tax (December 2022 Plant Balance * Property tax rate)			
31	Distribution property tax expense	$ 1	$ 1	
32	Transmission property tax expense	0	0	
33	General Plant property tax expense	0	0	
34	Impact to general taxes (Sum L70 through L74)	$ 1	$ 1	
35				
36	Total Operating Expenses (Depreciation + Amortization + Property Taxes)			
37	Distribution	$ 28,683	$ 7,978	
38	Transmission	1,349	352	
39	General Plant	8,187	3,834	
40	Total income taxes	$ 38,220	$ 12,165	
41				
42	Taxes	23.17%	23.17%	
43	Distribution	$ (6,646)	$ (1,849)	
44	Transmission	(313)	(82)	
45	General Plant	(1,897)	(888)	
46	Total income statement impact	$ (8,855)	$ (2,819)	
47				
48	Income Statement Impact (Operating expenses + Taxes)			
49	Distribution	$ 22,038	$ 6,130	
50	Transmission	1,036	271	
51	General Plant	6,290	2,946	
52	Total income statement Requirement	$ 29,364	$ 9,347	
53				
54	Retention Factor	76.55%	76.55%	
55				
56	Total Revenue Requirement (Capital Revenue Requirement + Income Statement impact/ Retention factor)			
57	Distribution	$ 56,966	$ 36,184	
58	Transmission	2,657	1,656	
59	General Plant	10,284	5,915	
60	Total Revenue Requirement	$ 69,906	$ 43,755	
61				

Grid Deferral Assumptions

CWIP spend is spent evenly throughout the year
Amount of CWIP spend has been adjusted to amounts reflected in the settlement agreement.

Timing of assets going in service
Distribution - Assumed 1 month delay from time of CWIP spend to asset placed in service.
Transmission - Assumed 6 month delay from time of CWIP spend to asset placed in service.
Communications - Assumed 3 month delay from time of CWIP spend to asset placed in service.
Advance DMS and Enterprise applications - assumed CWIP spend placed in service annually in December.
Deferral begins with Plant additions starting in June 2020.

Depreciation rates
Distribution - applied a total distribution depreciation rate excluding meters.
Transmission - applied a total transmission rate
Communication - applied a total communications depreciation rate
Advanced DMS - assumed a 10 year asset life
Enterprise application - assumed a 5 year life

Returns
Assumed the weighted average cost of capital as reflected in the company's settlement agreement.

O&M
Reflected estimated installation O&M expenses beginning June 2020.
Assumed no incremental on going O&M expenses.
Assumed new depreciation rates effective 9/1/2020.

Property Taxes
Property taxes begin the next calendar year after the asset is placed in service.

Deferral
Assumed deferral begins 6/1/2020.
Assumed plant additions stopped being eligible for deferral 1/1/2023.
Deferral of return, depreciation, property tax continued until 12/31/2023 on electric plant in service balances as of 12/31/2022.

Deferral recovery
Assumed a 5 year levelized amortization of the deferral.

Revenue Requirement
Assumes the test period was twelve months ended December 2022.
Assumed there was no additional update period after the test period.
Assumed rates were effective 1/1/2024.
Assumed rates were adjusted after the 5 year amortization of the deferral expired

Rate impacts
Allocations are based on 2018 cost of service study as presented in the current rate case.
For modeling purposes, forecasted distribution costs were allocated using a composite distribution plant allocator, excluding extra facilities and FERC accounts 370, 371 and 373.
In actuals, distribution costs will be allocated more specifically based on the individual FERC accounts they are booked to.
Does not include any savings that might be realized in the base rate cases as a result of the investments.
Percent increases shown based on present revenues annualized with riders as presented in current case

DUKE ENERGY PROGRES
E2 Sub 1219
NORTH CAROLINA RETAIL GRID IMPROVEMENT PLAN
SUMMARY OF DEFERRAL

DEP NC Grid Work Plan

Dollars in thousands (000s)	2020	2021	2022	2023
System CWIP Spend	106,873	163,678	215,201	
NC Retail CWIP Spend	91,967	138,356	197,877	
Cumulative In Service (Beg Mar 2020)	57,747	190,650	385,418	
Accum Depr	(272)	(4,218)	(12,895)	
Total Rate Base	57,475	186,432	372,524	
O&M (Beg Jan 2020)	1,873	3,951	4,225	
Depreciation (Beg Mar 2020)	272	3,946	8,677	12,164
Property Tax	-	209	691	1,397
Debt Return - Capital Asset	271	2,251	5,309	7,106
Debt Return - Deferred Balance	12	170	591	1,280
Equity Return - Capital Asset	908	7,542	17,787	23,809
Equity Return - Deferred Balance	40	569	1,979	4,287
Annual Deferral	3,376	18,639	39,258	50,043
Cumulative Deferral Balance	3,376	22,014	61,272	111,315

Sean P. Riley, Partner
601 South Figueroa Street
Los Angeles, CA 90017
sean.p.riley@pwc.com
Mobile: 802.730.3364

Position

Sean Riley is a dedicated member of PricewaterhouseCoopers' (PwC) National Power, Utility and Renewable Energy Practice. Sean currently has two roles within PwC's Utility practice. First, Sean is an Assurance Partner leading significant audit engagements in the Independent Power, Renewables and Regulated Utility sectors. In addition, Sean leads PwC's Complex Accounting and Regulatory Solutions (CARS) Team. In this role, Sean oversees a team of Utility sector specialists that advises clients on complex technical accounting and regulatory / ratemaking matters. In addition, Sean and the CARS team are responsible for the development of PwC's thought leadership related to the Power & Utilities Sector.

Sean previously completed a three-year tour as the Power & Utility technical leader in the Accounting Services Group within PwC's National Office.

Range of experience

Sean started his career with Coopers & Lybrand (predecessor company to PwC) in 1992 in Portland, Maine. Since that time, Sean has specialized in serving public and privately-owned clients in the Independent Power, Renewable Energy and Regulated Electric and Gas Utility sectors. Over his 27+ year career, Sean has provided leadership and direction around a variety of financial reporting and technical accounting matters, including regulatory accounting, rate-making, and other areas applicable to utilities, independent power and renewable energy companies.

Sean is a frequent speaker at PwC industry events, as well as for organizations such as the Edison Electric Institute, American Gas Association and NARUC.

Education

University of Vermont (1990, 1992) Business - Accounting

pwc

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 826

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Carolina Power & Light Company's	)	ORDER GRANTING MOTION
Petition for Authority to Place Certain	)	FOR RECONSIDERATION AND
Asset Retirement Obligation Costs	)	ALLOWING DEFERRAL OF COSTS
in a Deferred Account	)	

BY THE COMMISSION: On May 5, 2003, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC or Company) filed a motion requesting that the Commission reconsider that portion of its Order issued April 4, 2003, in the above-referenced docket, which denied PEC's request to defer the forward-requirements impact of the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143) and, instead, grant such request.

BACKGROUND

PEC's initial petition was filed on December 23, 2002. It concerned a request for authority to place certain Asset Retirement Obligation (ARO) costs in deferred accounts. PEC stated that such authority was needed so that the current regulatory treatment for these costs will not be altered due to PEC's adoption of Statement of Financial Accounting Standards No. 143 (SFAS 143), *Accounting for Asset Retirement Obligations.* To the extent necessary to permit the requested deferrals, PEC also moved for waiver of Regulatory Condition No. 16 adopted by the Commission by Order issued July 3, 1999, in Docket Nos. E-2, Sub 740, and G-21, Sub 377.

As explained by PEC in its initial petition, in June 2001, the FASB issued SFAS 143, effective for fiscal years beginning after June 15, 2002. SFAS 143, which is required to be implemented by PEC in order to comply with generally accepted accounting principles (GAAP), mandates a new method for measuring and accounting for certain AROs. Those obligations, as defined by SFAS 143, concern legal obligations associated with the retirement of tangible, long-lived assets. PEC further indicated that it expected that the only significant retirement cost constituting an ARO subject to SFAS 143 would be its obligation to decommission the radiated portions of its nuclear plants.

If a legally enforceable ARO, as defined by SFAS 143, is deemed to exist for a firm, a liability for the ARO must be measured and recorded on the firm's books in the period in which it is incurred. The liability must be recorded at fair value, that is, the amount that the firm would pay in the market to settle the liability. If market prices are not available, estimates of fair value can be calculated by discounting the estimated cash flows associated with the ARO to their present value at the date the liability is to be recorded.

At the time the liability is recorded, a corresponding and equivalent ARO asset is recorded on the firm's books, as part of the cost of the associated tangible asset. The ARO asset is depreciated over the life of the associated long-lived asset. Additionally, an accretion is added to the ARO liability each reporting period to account for the time value of money, so that at the time of retirement the recorded ARO liability will be sufficient to provide for the cash outlays necessary to meet the legal obligation. Thus, the ARO expense recorded each year during the life of the tangible asset generally includes two components: depreciation expense associated with the ARO asset and accretion expense measuring the change in the ARO liability due to the time value of money. The ARO liability and associated ARO asset may also change over time due to revisions in the timing or the amount of the original estimate of ARO costs. Such changes can affect the recorded expense in the period of change and/or future periods.

In addition to the forward-looking requirements of SFAS 143 described above, firms are also required to recognize the cumulative impact in the financial statements in the year of its implementation. This cumulative impact amounts to a "catch-up" entry on the firm's books, so that in future years the financial statements will appear as if the requirements of SFAS 143 had always been followed.

The FASB recognized that differences may exist between the requirements of SFAS 143 and the treatment of ARO costs for regulatory purposes, and accordingly provided that a regulated entity subject to Statement of Financial Accounting Standards No. 71 (SFAS 71), *Accounting for the Effects of Certain Types of Regulation*, could recognize a regulatory asset or liability for any differences between the two approaches, if the facts and circumstances meet the requirements of SFAS 71 for such recognition.

In its initial petition, PEC requested that the Commission authorize it to place all income statement impacts arising from the Company's adoption of Statement 143 in regulatory deferred accounts. The amounts proposed to be deferred included both the net cumulative and the forward-requirements impacts.

Regulatory Condition No. 16, adopted by the Commission in its Order issued July 13, 1999, in Docket Nos. E-2, Sub 740, and G-21, Sub 377, prohibits PEC from filing for any cost deferral prior to December 31, 2004. Thus, the Company requested a waiver of that condition.

By Order issued on April 4, 2003, the Commission granted the Company's request for waiver of Regulatory Con`ition No. 16 and approved PEC's request to defer the cumulative impact of SFAS 143, subject to certain conditions. However, the Commission denied PEC's request to defer the forward-requirements impact of SFAS 143.

In denying the request to defer the forward-requirements impact, the Commission stated that "[i]t simply cannot be determined from the record, as it presently exists, that the forward-requirements represent major expenditures or that they otherwise satisfy a condition of the Clean Smokestacks Bill [Bill] such that the Commission would have the authority to allow deferral of those costs as an exception to the rate freeze." The Bill, in particular G.S. 62-133.6(e), provides that, during the period of the rate freeze, June 20, 2002, through December 31, 2007, the Commission may allow the deferral of costs or revenues by a utility if the utility experiences "governmental action resulting in significant cost reductions or requiring major expenditures including but not limited to the cost of compliance with any law, regulation, or rule for the protection of the environment or public health, other than environmental compliance costs."

MOTION FOR RECONSIDERATION

In its motion for reconsideration, PEC requested that the Commission reconsider its decision not to allow deferral of the forward-requirements impact of SFAS 143 for the following reasons:

> (a) In its April 4, 2003 Order, the Commission found that the cumulative impact of adopting SFAS 143 is allowable under the Bill because SFAS 143 represents governmental action that results in a major expenditure. In support of its Petition filed December 23, 2002, PEC presented a preliminary and confidential attachment that provided the estimated effect of the cumulative adjustment caused by the adoption of SFAS 143 and a simplified example indicating the estimated 2003 forward-requirement impact, as further discussed below. PEC filed a simplified estimate of the 2003 impact because the Company considered the total impact, including the cumulative adjustment, to be the relevant amount for the purpose of compliance with the Bill and did not anticipate that the Commission would bifurcate the cumulative adjustment from the forward-requirements impact.
>
> (b) In its confidential and preliminary attachment, PEC assumed a 7.25% realized earnings rate on assets in its decommissioning trust fund and noted that "Actual trust earnings will vary considerably over time." This 7.25% is reasonable if trust earnings are examined from the perspective of the entire service life of the nuclear plants through decommissioning. As indicated in the December 23, 2002 Petition, SFAS 143 will not impact total amounts expensed if viewed over the entire life of a nuclear plant. However, 7.25% realized returns are not reasonable from the perspective of anticipated realized earnings during the five-year period of the rate freeze ending December 31, 2007, per the

Bill. Exhibit 1 to this filing includes a more realistic rate of return than was provided with PEC's previous filing. Significant financial impacts are shown during the five-year period ending December 31, 2007.

(c) The primary reason for the difference between the 7.25% overall return amount shown on the December 23, 2002 Petition and the 1.32% realized return amount per the attached Exhibit 1 is the effect of unrealized earnings.[1] Much of the trust is invested in equities and much of the equities' value will be realized at a time closer to decommissioning as they are sold in anticipation of liquidity needs associated with the commencement of decommissioning. Also, changes in market conditions can significantly affect realized earnings when analyzed on a year-by-year basis. One of the advantages of the Commission's currently-approved method is that a long-term rate of return is assumed in a levelized manner over the life of the nuclear plants, and the amount included in cost of service is not subject to short-term market conditions. This is not the case under SFAS 143.

(d) PEC's actual experience for the quarter ended March 31, 2003, is shown on Exhibit 2. PEC believes that the quarterly and projected annual impacts presented on this exhibit support the direction and magnitude of the five-year projected effects shown on Exhibit 1.

(e) In addition to the impact of prospectively changing to SFAS 143 for nuclear decommissioning as explained above, recent interpretive guidance indicates that disallowance of deferral accounting for the forward-requirements will result in accounting changes for cost of removal obligations associated with assets that are not legal AROs. Pursuant to SFAS 143, the cost of removal for these assets does not represent an ARO and therefore must be prospectively expensed as incurred.[2] The effect of that change would have been reduced cost of removal of approximately $13 million and $54 million for the quarter ended March 31, 2003, and the year ended December 31, 2002, respectively. PEC does not believe that the Commission intended to modify the prospective accounting for cost of removal in its previous Order in this docket.

[1] Even though it is possible that PEC could realize returns in excess of 7.25% in a given period due to the unpredictable nature of securities markets, this would not contradict the Clean Smokestacks Bill which authorizes deferral for significant cost reductions as well as major expenditures. PEC does not seek only to defer the forward-requirements when they exceed the current level included in its rates, but rather to defer all differences, positive or negative, from the currently-established level.

[2] The cumulative cost of removal for assets that do not have recognized AROs associated with them was $957 million as of January 1, 2003. This amount remains in PEC's accumulated depreciation as previously recorded because the Commission's Order issued April 4, 2003, allowed deferral of SFAS 143 impacts.

(f) PEC believes that the forward-requirements impact of adopting SFAS 143, as presented herein and on the attached exhibits, will be significant and should therefore be deferred.

COMMENTS

On May 9, 2003, the Commission issued an Order requesting comments on PEC's motion for reconsideration. Carolina Utility Customers Association, Inc. (CUCA) filed comments on May 23, 2003. Attorney General Roy Cooper (Attorney General) and the Public Staff – North Carolina Utilities Commission (Public Staff) filed comments on June 6, 2003.

CUCA, in its comments, opposed the deferral of the forward-requirements impact of SFAS 143 and asked the Commission to deny PEC's motion for reconsideration. CUCA opined that a "mere expectation or a belief on the part of [PEC] of a potential impact or an estimated effect does not rise to the level of a governmental action requiring major expenditures." CUCA further averred that, until a significant cost reduction is realized or a major expenditure is required, deferral is neither appropriate nor lawful.

The Attorney General commented that the information provided by PEC as reflected in its Exhibit 1 was not sufficient as a basis for modifying the Commission's original Order. Specifically, the Attorney General argued that the rate of return on trust funds expected to be realized over the entire service life of the nuclear plants through decommissioning should be used consistently in developing and comparing SFAS 143 costs to the level of decommissioning costs currently included in rates.

As noted by the Attorney General, PEC, among other things, applied an expected rate of return of 1.32% to trust funds in estimating the forward-requirements impact of SFAS 143 during the five-year period of the "rate freeze" ending December 31, 2007.[3] The Attorney General also observed that in the Company's motion for reconsideration "PEC states that the previously used 7.25% rate of return 'is reasonable if trust earnings are examined from the perspective of the entire service life of the nuclear plants through decommissioning.'"

Consequently, because of the rate-of-return inconsistency present in PEC's cost comparison, the Attorney General is of the opinion that "PEC's 'Exhibit 1' does not answer the Commission's main question about deferral of SFAS 143's forward requirements – whether SFAS 143 creates the need for major expenditures from 2003 forward." Therefore, the Attorney General is of the view that the Commission should not accept PEC's Exhibit 1 as a basis for modifying the Commission's original Order.

[3] The Clean Smokestacks Bill provides that the base rates of the investor-owned public utilities, subject to its provisions, shall remain unchanged from the effective date – June 20, 2002 - of this provision, i.e., G.S. 62-133.6(e), through December 31, 2007.

In its comments, the Public Staff supported PEC's request. The Public Staff restated its view, as previously stated in its initial comments, that deferral of the cumulative impact as well as the forward-requirements impact would preserve the historical and current Commission treatment of such costs for current regulatory purposes.

The Public Staff further opined that the cumulative and forward-requirements impacts of SFAS 143 are matters that are closely related and as such should be considered collectively and not separately. The Public Staff argued that the ultimate ARO liability is unaffected by the adoption of SFAS 143 and that the interim expense increases – or deferred costs – arising from its adoption will eventually be offset by expense decreases – or deferred credits - which, ultimately, will be incorporated into the forward-requirements impact. Therefore, according to the Public Staff, deferral of the forward-requirements impact will, in effect, itself function to "amortize" the deferred cumulative impact of SFAS 143. Also, the Public Staff stated that, if the Commission does not approve the deferral of the forward-requirements impact, it will be unresolved as to how the deferred cumulative impact will be amortized.

Additionally, the Public Staff recommended that the Commission confirm that it did not intend to modify the prospective accounting for cost of removal obligations associated with assets that are not legal AROs. As the Public Staff noted, historically, cost of removal has been a component of PEC's depreciation rates as approved by this Commission. Consequently, such costs are being accrued and recognized as operating revenue deductions over the life of the related assets, rather than being charged to expense when actually paid. It is the Public Staff's position that any changes in the regulatory accounting for cost of plant removal should be considered in a general rate case or other appropriate proceeding.

REPLY COMMENTS

In responding to CUCA in its reply comments, PEC stated that it had supported its projections with actual data. PEC commented that it does not agree with CUCA that reasoned estimates of future impacts cannot represent the presence of governmental action resulting in significant cost reductions or major expenditures. PEC opined that, even if valid, CUCA's argument regarding the use of estimates is irrelevant in this proceeding because ample actual information has been supplied in addition to the $126 million effect shown on Exhibit 1 of the motion for reconsideration. Additionally, PEC argued that CUCA's comments also ignored completely the significant effect to PEC's cost of removal obligations associated with assets that are not legal AROs.

Regarding the Attorney General's comments, PEC stated that the Attorney General ignored the cost of removal effect and the actual decommissioning impact presented in Exhibit 2 of the motion for reconsideration. PEC commented that the Attorney General's argument for a longer-term rate of return than was used by the Company is illogical because the Commission's clear reason for denying deferral of the forward-requirements impact was the Clean Smokestacks Bill. Accordingly, PEC averred that the appropriate timeframe for analysis of this issue is the five-year period ending December 31, 2007.[4] Finally, in responding to the Attorney General, PEC stated that, for the reasons previously provided at Paragraph 5(c) of its motion for reconsideration, the actual rate of return realized during this relevant period will likely be significantly less than the 7.25% recommended in the Attorney General's Comments.

PEC stated that:

> SFAS 143, which was effective for PEC on January 1, 2003, represents generally accepted accounting principles concerning the recording of expenses associated with the retirement of long-lived assets. Any regulated utility can follow accounting practices which are inconsistent with SFAS 143, or any other accounting directive, if it is so authorized by its regulatory governing body pursuant to Statement No. 71 of the Financial Accounting Standards Board, *Accounting for the Effects of Certain Types of Regulation* ("SFAS 71"). Therefore, PEC sought regulatory approval to defer the effects of SFAS 143 by its Petition filed on December 23, 2002, in this docket. PEC will be able to defer all effects of SFAS 143 pursuant to the enabling authority contained in SFAS 71 if the Commission approves such deferral. Lacking such approval by the Commission, PEC must adopt and follow SFAS 143 for its NC retail jurisdiction.

PEC commented that based on guidance provided by PEC's external auditors, the Securities and Exchange Commission's (SEC's) Staff has concluded that SFAS 143 forbids the recording of retirement costs for any asset that is not an ARO. For PEC, this includes all long-lived assets other than its four nuclear generating units. According to PEC, the underlying logic is that if an asset does not qualify for formal recognition as an ARO, accrual of retirement costs is inconsistent with SFAS 143. PEC stated that it has accrued cost of removal on all of its long-lived assets through its depreciation rates as prescribed most recently in the Commission's 1988 general rate case order issued in Docket No. E-2, Sub 537. The Company noted that such accruals have never been prohibited by any pronouncement of the Financial Accounting Standards Board prior to promulgation of SFAS 143. According to PEC, the only manner in which PEC can continue its traditional recording of the cost of removal through its depreciation rates, and continue to record decommissioning costs consistent with the Commission's

[4] As stated earlier herein, in denying the request to defer the forward-requirements impact, the Commission stated that "[i]t simply cannot be determined from the record, as it presently exists, that the forward-requirements represent major expenditures or that they otherwise satisfy a condition of the Clean Smokestacks Bill [Bill] such that the Commission would have the authority to allow deferral of those costs as an exception to the rate freeze." The Bill, in particular G.S. 62-133.6(e), provides that, during the time period ending December 31, 2007, the Commission may allow the deferral of costs or revenues by a utility if the utility experiences "governmental action resulting in significant cost reductions or requiring major expenditures i`clud ing but not limited to the cost of compliance with any law, regulation, or rule for the protection of the environment or public health, other than environmental compliance costs."

approved methodology, is to receive an Order from the Commission specifically authorizing PEC to defer the forward-requirements impact of SFAS 143.

In concluding its reply comments, PEC opined that it had provided ample evidence in its motion for reconsideration and reply comments that the forward-requirements impact of SFAS 143, in addition to the cumulative impact, was significant. Accordingly, PEC requested that the Commission reject the comments of CUCA and the Attorney General and grant deferral of the forward-requirements impact of SFAS 143.

In a filing made July 10, 2003, PEC presented additional information regarding the impact of SFAS 143 on the Company based in large measure on the six-month period ended June 30, 2003. Among other things, the filing indicated that, when based on the aforesaid six-month period, PEC's 2003 nuclear decommissioning costs, on an annualized basis, would be $20.4 million greater under SFAS 143 as compared to the historical expense level contained in the Commission's Order of September 7, 1995, issued in Docket No. E-2, Sub 682.

CONCLUSIONS

For reasons discussed below, the Commission is of the opinion, and so concludes, that good cause exists to grant PEC's motion for reconsideration and approve its request to defer the forward-requirements impact of SFAS 143.

As noted above, the Commission in its Order of April 4, 2003, denied the Company's initial request for deferral of the forward-requirements impact of SFAS 143. In so doing, the Commission stated that "[i]t simply cannot be determined from the record, as it presently exists, that the forward-requirements represent major expenditures or that they otherwise satisfy a condition of the Clean Smokestacks Bill [Bill] such that the Commission would have the authority to allow deferral of those costs as an exception to the rate freeze." The Bill, in particular G.S. 62-133.6(e), provides that during the rate freeze period, which began with the effective date of this provision of the Bill - June 20, 2002 - and ends December 31, 2007, the Commission may allow the deferral of costs or revenues by a utility if the utility experiences "governmental action resulting in significant cost reductions or requiring major expenditures including but not limited to the cost of compliance with any law, regulation, or rule for the protection of the environment or public health, other than environmental compliance costs."

As noted above, in its motion for reconsideration, PEC explained that as part of its initial filing in this docket it included a simplified example of the forward-requirements impact of SFAS 143. The Company stated that it had done so because it considered the total impact of the present accounting pronouncement, including the cumulative impact, to be the relevant amount for the purpose of compliance with the Bill and did not anticipate that the Commission would bifurcate the cumulative impact from the forward-requirements impact.

The Company further explained that in developing the simplified example of the forward-requirements impact it used, among other things, a realized earnings rate of 7.25%. PEC noted that such a rate was reasonable if trust fund earnings are examined over the entire service life of the nuclear plants through decommissioning. However, the Company observed that use of a 7.25% return was not reasonable from the standpoint of anticipated realized earnings during the five-year period of the rate freeze.

Exhibit 1 to the Company's motion for reconsideration is a schedule which presents a calculation of the annual forward-requirements impact for each fiscal year during the five-year rate freeze period ending December 31, 2007, i.e., 2003 through 2007. That calculation includes partial offsets to depreciation and accretion expenses. Those offsets represent the levels of earnings expected to be realized on the external decommissioning trust fund during the present five-year period. They are based on a projected earnings rate of 1.32%, which represents the Company's actual experience during the previous five-year period ended December 31, 2002.

The Attorney General argued that 7.25% was the appropriate trust fund earnings rate to be used consistently over the service life of the nuclear plants through decommissioning, including the five-year period of the rate freeze ending December 31, 2007, in developing and comparing SFAS 143 costs to the level of decommissioning costs currently included in rates.

The Commission disagrees with the Attorney General. As the Commission understands it, absent a Commission Order to the contrary, under SFAS 143, for both accounting and reporting purposes, the Company is required to recognize, on a current basis, the earnings actually realized on the trust fund. Indeed, one of the major, if not the major, differences between the periodic levels of decommissioning costs determined under the Commission's historical approach and that determined under SFAS 143 arises from the fact that the former approach is based on a levelized or uniform earnings rate over the service life of the nuclear plants through decommissioning, whereas the latter methodology, effectively, produces a variable rate. That results because the rate, in part, is a function of periodic earnings actually realized on the trust fund, which vary over time. As indicated, that is not the case with the Commission's historical approach.

Accordingly, the Commission is of the opinion, and so concludes, that for the present purpose it is entirely appropriate, in estimating the forward-requirements impact of SFAS 143, to use the levels of earnings the Company can reasonably be expected to achieve during the period 2003 through 2007. Further, based on the information of record, the Commission is of the opinion, and so concludes, that the estimated earnings rate of 1.32% employed by PEC in determining the annual levels of earnings it expects to actually realize on the trust fund during the aforesaid period is reasonable.

As previously stated, CUCA opined that a "mere expectation or a belief on the part of [PEC] of a potential impact or an estimated effect does not rise to the level of a governmental action requiring major expenditures." CUCA further averred that, until a significant cost reduction is realized or a major expenditure is required, deferral is neither appropriate nor lawful.

The Commission disagrees with CUCA. PEC's implementation of SFAS 143 with respect to the forward-requirements impact, which would be mandatory under GAAP, absent an Order from the Commission to the contrary, would require the Company to record the forward-requirements impact as an item of expense in its books, and reflect the effect of such expense in its financial reports, when incurred. Under SFAS 143, such costs are considered to be incurred by PEC beginning on January 1, 2003, notwithstanding the fact that the accrual of same requires the use of estimates. Clearly, the use of reasonable and appropriate estimates as well as reasonable and appropriate assumptions and judgment is inherent in the application of GAAP. The Commission therefore concludes that CUCA's argument is without merit.

Whether the costs in question were precipitated by a governmental action does not appear to be in dispute. In any event, that matter was addressed by the Commission in its Order issued on April 4, 2003, in this docket, and need not be revisited here. Suffice it to say that the Commission has previously concluded that the required implementation of SFAS 143 is, effectively, a governmental action.

PEC stated that, in its initial filing, it considered the total impact, i.e., the cumulative impact and the forward-requirements impact, of SFAS 143 to be the relevant amount for the purpose of compliance with the Bill and did not anticipate that the Commission would bifurcate the cumulative adjustment from the forward-requirements impact. The Public Staff argued that the cumulative and forward-requirements of SFAS 143 should be considered collectively and not separately. The Public Staff stated that those impacts are closely related and that the forward-requirements impact would, effectively, operate to "amortize" the deferred cumulative impact of SFAS 143.

The Commission is of the opinion that, while it may be reasonable to view the implementation of SFAS 143 as a single "governmental action" for the present purpose, its provisions clearly require the recognition of two different major categories of costs: cumulative costs and forward-requirements costs. Accordingly, the Commission concludes that the arguments of PEC and the Public Staff are without merit.

Regarding whether the present costs constitute a major expenditure as envisioned by the Bill, the Commission is of the opinion that they do. In Exhibit 1 of PEC's motion for reconsideration, the Company estimated that, for the period 2003 through 2007, its total company forward-requirements costs in the aggregate under SFAS 143 would be $125.9 million greater than the aggregate decommissioning expense projected under the currently approved approach. Based on that consideration and all other information of record, the Commission concludes that the forward-requirements impact of SFAS 143 when considered collectively constitutes a major expenditure as contemplated by the Bill.

Therefore, having concluded (1) that the estimated 1.32% earnings rate employed by PEC in determining the annual levels of earnings it expects to actually realize on the nuclear decommissioning external trust fund during the aforesaid period is reasonable and appropriate for use in the present regard, (2) that the forward-requirements costs will, in fact, be incurred and recorded as an item of expense in PEC's books, absent deferral, and (3) that the imposition of such costs results from governmental action and, absent deferral, would collectively constitute a major expenditure under the Bill, and in consideration of (4) the Public Staff's position that PEC's requests should be approved and (5) all other information of record, the Commission is of the opinion, and so concludes, that it should reconsider that portion of its Order issued April 4, 2003, in this docket, which denied PEC's request to defer the forward-requirements impact of SFAS 143 and, instead, grant such request.

There is one final matter that needs to be addressed. As previously mentioned, PEC commented that based on guidance provided by PEC's external auditors, the SEC's Staff has concluded that SFAS 143 forbids the recording of retirement costs for any asset that is not an ARO. For PEC, this includes all long-lived assets other than its four nuclear generating units. As noted above, the Public Staff recommended that the Commission confirm that it did not intend to modify the prospective accounting for cost of removal obligations associated with assets that are not legal AROs.

As the Public Staff noted, historically, cost of removal has been a component of PEC's depreciation rates as approved by this Commission. As PEC noted, it has accrued cost of removal on all of its long-lived assets through its depreciation rates as prescribed most recently in the Commission's 1988 general rate case order issued in Docket No. E-2, Sub 537.

Depreciation expense, which in part is a function of depreciation rates, was included as a component of the Company's North Carolina retail (N.C. retail) cost of service established in the context of the Company's last general rate case proceeding. Consequently, the recovery of that expense, which includes the cost of removal, is now provided for in the rates and charges PEC is authorized to charge for its sales of service with respect to its N.C. retail operations. Consistent with the economic consequences of that regulatory treatment, the cost of removal is accrued and recognized as an operating revenue deduction over the useful life of the related assets, rather than waiting to record the expense until the assets are actually removed and the related costs actually paid. It is the Public Staff's position that any changes in accounting for those costs should be considered in a general rate case or other appropriate proceeding.

In consideration of the fact that recovery of the cost of removal in question has been and is now provided for in the Company's rates, as approved in the context of its last general rate case proceeding as well as other past proceedings, and in consideration of the magnitude of such costs, the Commission is of the opinion, and so concludes, that, as suggested by the Public Staff, it is entirely appropriate, to avoid any misconstruction, for the Commission to confirm that it did not intend to, and did not, prospectively or otherwise, modify the regulatory treatment previously adopted for the cost of removal as provided for most recently in the context of the Company's last general rate case proceeding. Additionally, the Commission is of the opinion, and so concludes, that the Company should be, and hereby is, explicitly placed on notice that any proposed changes in the cost of removal for long-lived assets and/or in the accounting for such costs must be submitted to the Commission for its approval in the context of a general rate case or other appropriate proceeding prior to implementation.

IT IS, THEREFORE, ORDERED as follows:

1. That PEC's motion requesting that the Commission reconsider that portion of its Order issued April 4, 2003, in this docket, which denied the Company's request to defer the forward-requirements impact of the FASB's SFAS 143, shall be, and hereby is, allowed.

2. That, on reconsideration, PEC's request to defer the forward-requirements impact of SFAS 143 shall be, and hereby is, approved subject to the following conditions, to the end that PEC's adoption of SFAS 143 shall, in effect, have no impact, currently or prospectively, on the Company's North Carolina retail operations, pending further order of the Commission:

a. That the intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking practices for nuclear decommissioning costs and other ARO costs.

b. That the adoption of SFAS 143 shall have no impact on PEC's operating results or return on rate base for North Carolina retail regulatory purposes and that the net effect of the deferral accounting allowed shall be to reset PEC's North Carolina retail rate base, net operating income, and regulatory return on common equity to the same levels as would have existed had SFAS 143 not been implemented.

c. That the implementation of SFAS 143 for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission.

d. That the individual line items and account balances in the quarterly ES-1 surveillance filings and the annual cost of service studies filed by PEC with the Commission shall be stated as if SFAS 143 had not been implemented by PEC.

e. That when PEC files its annual report required by Commission Rule R1-32, it shall also file a reconciliation of the account balances set forth in that report (both total company and North Carolina) with the account balances set forth in the annual cost of service studies filed with the Commission.

f. That no portion of the total ARO asset or liability shall be included in rate base for North Carolina retail accounting or ratemaking purposes.

g. That no portion of the total ARO asset or liability shall be included in the Construction Work in Progress base to which PEC applies its AFUDC [Allowance for Funds Used During Construction] rate.

h. That neither the depreciation rates utilized by PEC nor the depreciable bases to which it applies those rates shall be changed due to the implementation of SFAS 143.

i. That PEC shall file with the Commission the journal entries setting forth the initial implementation of SFAS 143 and all other entries related to SFAS 143 for calendar year 2003, as well as all entries implementing the deferrals allowed by the Commission's Orders.

j. That all entries made and amounts recorded as a result of the implementation of SFAS 143 and the deferrals allowed by the Commission's Orders shall be subject to ongoing review by the Commission, the Public Staff, and other parties to this docket.

k. That the deferral accounting treatments allowed by the Commission's Orders shall not prejudice any party from taking issue with the amount or the treatment of any deferral of ARO costs in a rate or other appropriate proceeding, including a proceeding initiated in Docket No. E-100, Sub 56 for the purpose of determining nuclear decommissioning expenses.

3. That the Commission, in its Order issued April 4, 2003, in this docket, did not intend to, and did not, modify the regulatory treatment previously established for cost of removal obligations associated with assets that are not legal AROs.

4. That, absent an explicit Commission order to the contrary, PEC shall continue to accrue cost of removal obligations associated with assets that are not legal AROs through its depreciation rates as prescribed most recently in the Commission Order ruling on the Company's application for a general rate increase in Docket No. E-2, Sub 537.

5. That PEC shall submit all proposed changes in the cost of removal for all long-lived assets and/or in the accounting for such costs, if any, to the Commission for

its approval prior to implementation. Such changes, when submitted, shall be considered in the context of a general rate case or other appropriate proceeding.

6. That, except as modified herein, the Commission Order issued April 4, 2003, in this docket, shall remain in full force and effect.

ISSUED BY ORDER OF THE COMMISSION.

This the 12th day of August, 2003.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

Chairman Jo Anne Sanford and Commissioner Lorinzo L. Joyner did not participate.

HD081203.01

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

			North Carolina Retail Operations					
Line No.	**Description**	**Total Company Per Books** (a)	**Per Books**	**Accounting Adjustments** (c)	**Before Proposed Increase**	**Revenue and Expenses from Proposed Increase** (e)	**After Proposed Increase**	
		(Col. 1)	**(Col. 2)**	**(Col. 3)**	**(Col. 4)**	**(Col. 5)**	**(Col. 6)**	
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (318,129)	$ 3,339,374	$ 585,961	$ 3,925,336	
	Electric operating expenses:							
	Operation and maintenance:							
2	Fuel used in electric generation	1,429,144	881,642	(46,419)	835,224		835,224	
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798	
4	Other operation and maintenance expense	1,546,719	1,050,819	(177,306)	873,513	2,164	875,677	
5	Depreciation and amortization	1,060,260	669,787	301,368	971,156		971,156	
6	General taxes	153,362	102,197	2,018	104,215		104,215	
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971	
8	Net income taxes	150,622	112,986	(74,904)	38,082	134,925	173,007	
9	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)	
10	Total electric operating expenses	4,736,071	2,982,032	1,312	2,983,344	137,089	3,120,433	
11	Operating income	$ 946,351	$ 675,472	$ (319,441)	$ 356,031	$ 448,872	$ 804,903	
12	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 926,524 (d)	$ 10,785,574	$ 74,407 (f)	$ 10,859,981	
13	Rate of return on North Carolina retail rate base		6.85%		3.30%		7.41%	

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

				North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
Line No.	Description	Dec. 31, 2018 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	$ 8,108,191	47.00%	$ 5,069,220	4.15%	$ 210,604	$ 5,104,191	4.15%	$ 212,057
2	Members' equity (a)	8,717,931	53.00%	5,716,354	2.54%	145,427	5,755,790	10.30%	592,846
3	Total	$ 16,826,122	100.00%	$ 10,785,574 (b)		$ 356,031 (c)	$ 10,859,981 (b)		804,903
4	Operating income before increase (Line 3, Column 5)								356,031
5	Additional operating income required (Line 3 minus Line 4)								448,872
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								(337)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)								137,426
8	Additional revenue requirement								$ 585,961
9	Revenue Adjustments (d)								$ (122,342)
10	Net Increase								$ 463,619

-- Some totals may not foot or compute due to rounding.

Notes: (a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes 23.1693% (Col. 7)	Amortization of ITC (Col. 8)	Operating Income
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	(52,114)	-	(172,813)
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	3,304	-	10,955
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	(13,653)	-	(45,273)
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	534	-	1,771
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	63,161	-	128,547
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	556	-	1,843
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	(9,747)	(1,481)	(30,841)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	(17,857)	-	(59,213)
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	(24,553)	-	(81,419)
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	(304)	-	(1,007)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	4,542	-	15,060
14		Update benefits costs	-	-	-	(3,060)	-	-	709	-	2,351
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	1,444	-	4,788
16	*	Amortize rate case costs	-	-	-	701	-	-	(162)	-	(539)
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	341	-	1,129
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	988	-	3,276
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	5,414	-	17,952
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	(2,183)	-	2,183

Smith
Exhibit 1
Page 3

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes 23.1693% (Col. 7)	Amortization of ITC (Col. 8)	Operating Income
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	123	-	(123)
23	*	Adjust cash working capital	-	-	-	-	-	-	122	-	(122)
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	(1,204)	-	(3,993)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	(20,760)	-	(68,841)
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	21	-	70
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	(10,129)	-	(33,588)
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	1,767	-	5,859
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	(1,144)	-	(3,794)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	(4,565)	-	(15,138)
35		Adjust Purchased Power	-	-	(1,965)	-	-	-	455	-	1,510
36		Total adjustments	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ (74,904)	$ (1,481)	$ (319,441)

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	224,927	-	224,927
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,258)	-	(14,258)
3	*	Normalize for weather	-	-	-	-	-	-	-	-	58,926	-	58,926
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,306)	-	(2,306)
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,826)	-	(11,826)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,313)	(94,010)	(261,323)
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,399)	-	(2,399)
8		Annualize depreciation on year end plant balances	-	-	-	-	-	-	-	-	40,141	-	40,141
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,064	-	4,064
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,070	120,182	197,252
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	105,972	29,499	135,471
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,311	-	1,311
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,602)	-	(19,602)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,060)	-	(3,060)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,232)	-	(6,232)
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	701	186	887
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,470)	-	(1,470)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,871)	(5,835)	(7,707)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,264)	31	(4,232)
20	*	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,366)	1,621	(21,745)
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,841)	-	(2,841)

Smith
Exhibit 1
Page 3
(continued)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	159	(2,447)	(2,288)
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,197	-	5,197
26		Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,601	(8,037)	81,564
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,757	-	5,757
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
29	*	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,717	42,594	86,311
30		Adjust other revenue	-	-	-	-	-	-	-	-	4,150	-	4,150
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(234)	-	(234)
32	*	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,626)	(2,965)	(10,591)
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,939	-	4,939
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,703	2,230	21,933
35		Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,965)	-	(1,965)
36		Total adjustments	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 415,773	$ 83,923	$ 499,696

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 580,558	$ 19,386,469
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(102,448)	(8,144,508)
3	Net electric plant		16,126,825	10,763,851	478,110	11,241,961
4	Add: Materials and supplies	4c	1,076,701	754,774	(151,079)	603,695
5	Working capital investment	4d	(642,895)	(375,172)	891,707	516,535
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(189,284)	(1,521,912)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 926,524	$ 10,785,574

-- Some totals may not foot or compute due to rounding.

I/A

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	North Carolina Retail Operations: Accounting Adjustments (Col. 3)	North Carolina Retail Operations: As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (198,752)	$ 9,857,768
2	Transmission Plant	2,746,389	1,643,263	168,445	1,811,708
3	Distribution Plant	6,944,764	6,052,263	588,771	6,641,034
4	General Plant	628,616	465,435	46,355	511,790
5	Intangible Plant	527,370	358,178	3,102	361,280
6	Subtotal	27,398,830	18,575,658	607,921	19,183,580
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 580,558	$ 19,386,469

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Page 4a

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ 1,462	$ (4,389,296)
2	Transmission Reserve	(816,198)	(488,611)	(20,202)	(508,814)
3	Distribution Reserve	(3,235,148)	(2,819,386)	(84,708)	(2,904,094)
4	General Reserve	(167,536)	(124,045)	17,197	(106,848)
5	Intangible Reserve	(322,831)	(219,260)	(16,197)	(235,457)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (102,448)	$ (8,144,508)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

8	Steam production plant	5.46%
9	Nuclear production plant	5.61%
10	Hydro production plant	0.52%
11	Other production plant	2.18%
12	Transmission plant	0.00%
13	Distribution plant	0.00%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 122,062	$ 74,591	$ 2,639 (a)	$ 77,230
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	235,801	144,097	2,639	146,735
4	Other electric materials and supplies and stores clearing	840,900	610,677	(153,718)	456,960
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (151,079)	$ 603,695

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(27,013)	(b)	133,128	74,407	(c)	207,535
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		918,720		481,429	-		481,429
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		891,707		633,123	74,407		707,530
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 891,707		$ 516,535	$ 74,407		$ 590,942

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	NC RETAIL		Reference
1	Additional base revenue requirement	$	585,961	Smith Exhibit 1
2	REVISED Annual EDIT Rider 1		7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback		(127,633)	Smith Exhibit 4
4	Regulatory Asset and Liability Rider		(2,091)	Smith Exhibit 5
5	Subtotal		(122,342)	Sum L3 - L17
6	Net Revenue Increase	$	463,619	

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Smith Exhibit 3
2018 NC EDIT Rider revised for the change in Federal Income Tax rate from 35% to 21% due to the December 22, 2017 enactment of the Federal Tax Cuts and Jobs Act (the "Act")

(Dollars in thousands)

LEVELIZED NC EDIT RIDER CREDIT

Line No.	Item	Annual Revenue Requirement Current Rider at 35% Federal Income Tax Rate (a)		Revised Rider at 21% Federal Income Tax Rate (b)	
1	Total NC retail regulatory liability to be amortized	($150,466)	1/	($150,466)	1/
2	Multiplied by 1 minus old tax rate (L8, col a)			62.9401%	
3	Balance without tax gross up (L1 x L2)			($94,703)	
4	Divided by 1 minus new tax rate (L8, col b)			76.4964%	
5	Balance with gross up at new tax rate (L3/ L4)			($123,801)	
6	Annuity factor (L18)	3.5454	2/	3.5287	
7	Levelized rider EDIT reg liability (L1/ L6 for col a, L5/L6 for col b)	(42,440)		(35,084)	
8	One minus composite income tax rate	62.9401%	3/	76.4964%	4/
9	Net operating income effect (L7 x L8)	(26,712)		(26,838)	
10	Retention factor	0.6273883	5/	0.7625199	6/
11	Levelized rider EDIT credit (L9 / L10)	($42,577)		($35,196)	
12	KWh Sales	37,312,555,626	7/	37,312,555,626	7/
13	EDIT Rider $ per kWh (L11 x 1000 / L12)	($0.00114)	8/	($0.00094)	
14	Impact to NC EDIT Rider with Federal Income Tax Rate Change (L11b -L11a)			$7,381	
	Annuity Factor				
15	Number of years	4		4	
16	Payment per period	1		1	
17	After tax rate of return	6.372%	9/	6.635%	10/
18	Present value of 1 dollar over number of years with with 1 payment per year	3.4358		3.4153	
19	1 plus (interest rate divided by two)	1.0319		1.0332	
20	Annuity factor (L16 x L17)	3.5454		3.5287	

1/ NCUC Form E-1, Item 10, NC-3201, Line 1 filed in NCUC docket E-2 Sub 1142.
2/ Peedin Revised Exhibit 2, Schedule 1(a), Line 6 filed in NCUC docket E-2 Sub 1142.
3/ One minus composite income tax rate 37.0599% per Peedin Revised Exhibit 2, Schedule 1, Line 4 filed in NCUC docket E-2 Sub 1142.
4/ One minus composite income tax rate 23.5036% in Smith Exhibit 3, Page 2 of 2 Line 3 col.(b)
5/ Peedin Revised Exhibit 1, Schedule 1-2, Line 14, Column (d) filed in NCUC docket E-2 Sub 1142.
6/ Smith Exhibit 3, Page 2 of 2 Line 7 col.(b)
7/ Adjusted test period kWh sales per DEP Compliance Exhibit No.6, line 2 filed in NCUC docket E-2 Sub 1142.
8/ EDIT Rider $ per kWh in DEP Compliance Exhibit No.6, line 3 filed in NCUC docket E-2 Sub 1142.
9/ Peedin Revised Exhibit 2, Schedule 1(a), Line 9 Cost of Capital Net of Tax filed in NCUC docket E-2 Sub 1142.
10/ Smith Exhibit 3, Page 2 of 2 Line 10 col.(b)

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Smith Exhibit 3

SMITH
Exhibit No. 3

2018 NC EDIT Rider revised for the change in Federal Income Tax rate from 35% to 21% due to the December 22, 2017 enactment of the Federal Tax Cuts and Jobs Act (the "Act")

INPUTS

Line No.	**Inputs**	Based on 35% Federal Income Tax Rate		Revised with 21% Federal Income Tax Rate	
		(a)		(b)	
1	State income tax rate	3.1691%	1/	3.1691%	1/
2	Federal income tax rate	35%	2/	21%	
3	Composite income tax rate (L1 + (1 - L1) x L2)	37.0599%		23.5036%	
4	Regulatory fee	0.13975%	3/	0.13975%	3/
5	Uncollectibles rate	0.18000%	4/	0.18000%	4/
6	Debt retention factor in col (b): ((1 - L5) x (1 - L4))	0.996803	5/	0.996805	
7	Equity retention factor in col (b): (L6 x (1 - L3))	0.6273883	6/	0.7625199	

	Cost of Capital Net of Tax Rate	Capital Structure	Cost Rates	Net of Tax Rate		Net of Tax Rate
8	Long-term debt (Capital Structure x Rate x (1 - L3)	48.00%	4.050%	1.224%	7/	1.487%
9	Common equity (Capital Structure x Rate)	52.00%	9.90%	5.148%	7/	5.148%
10	Gross Return Requirement (L8 + L9)	100.00%		6.372%	7/	6.635%

1/ Peedin Revised Exhibit 1, Schedule 1-3, Line 6, Column (a) filed in NCUC docket E-2 Sub 1142.
2/ Peedin Revised Exhibit 1, Schedule 1-3, Line 7, Column (a) filed in NCUC docket E-2 Sub 1142.
3/ Peedin Revised Exhibit 1, Schedule 1-2, Line 9, Column (d) filed in NCUC docket E-2 Sub 1142.
4/ Peedin Revised Exhibit 1, Schedule 1-2, Line 7, Column (d) filed in NCUC docket E-2 Sub 1142.
5/ Peedin Revised Exhibit 1, Schedule 1-2, Line 10, Column (d) filed in NCUC docket E-2 Sub 1142.
6/ Peedin Revised Exhibit 1, Schedule 1-2, Line 14, Column (d) filed in NCUC docket E-2 Sub 1142.
7/ Captal Structure, Cost Rates amd Net of Tax Rates in col (a) from Peedin Revised Exhibit 2, Schedule 1(a), Lines 7 through 9 filed in NCUC docket E-2 Sub 1142.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

			Federal EDIT - Protected NC Retail	Federal EDIT - Unprotected, PP&E related NC Retail	Federal EDIT - Unprotected, non PP&E related NC Retail	NC EDIT NC Retail	Deferred Revenue NC Retail	Total NC Retail
			(A)	(B)	(C)	(D)	(E)	(F)
1	Regulatory Federal EDIT liabilIty including gross up on the books as of 12/31/2018, based on 2017 tax returns	[1]	$ (854,917)	$ (326,704)	$ 4,862	$ (23,726)		(1,200,485)
2	Adjustment to implement ASU 2018-02	[1]			$ (34)	$ -		(34)
3	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2018-12/31/2018	[1]	$ 31,642		$ (31,642)	$ -		-
4	Regulatory Federal EDIT liability including gross up as of 12/31/2018, adjusted for the implementation of ASU 2018-02	[1]	$ (823,275)	$ (326,704)	$ (26,813)	$ (23,726)	$ -	(1,200,519)
5	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2019-8/31/2020	[1]	$ 52,737		$ (52,737)	$ -		-
6	Deferred revenues related to 2017 Federal Tax Rate Change as of 12/31/2018	[1]					$ (108,392)	(108,392)
7	Other projected updates through 2/29/2020	[2]					$ (1,923)	(1,923)
8	Regulatory liabilIty for federal tax change including gross up for NC Retail, for Year 1 rider calculation (Sum of L4 to L7)		$ (770,539)	$ (326,704)	$ (79,550)	$ (23,726)	$ (110,315)	(1,310,833)
9	Annual Amortization percentage		3.70%	5.00%	20.00%	20.00%	50.00%	9.44%
10	Liability for Annual amortization amount (Col A: L1 , Col B to E: L8)		$ (854,917)	$ (326,704)	$ (79,550)	$ (23,726)	$ (110,315)	(1,395,212)
11	Annual amortization amount (L9 x L10)	[3]	(31,642)	(16,335)	(15,910)	(4,745)	(55,157)	(123,790)
12	Years of rider amortization		27.02	20	5	5	2	11

[1] Excess deferred tax liability (EDIT) as of 12/31/2018 by jurisdiction, and forecast transition to new rates effective date between categories based on Tax analysis of ADIT.
Federal EDIT related to the federal tax changes booked to the 0254036 and 0254038 accounts is included in other Working Capital in the per books cost of service.
NC EDIT related to the NC state tax reduction deferred to the 0254150 account not included for recovery in NC EDIT rider approved in prior DEP NC rate case.
This NC EDIT is included in other Working Capital in the per books cost of service.
Revenues deferred for federal tax changes with accrued returns in the 0229010 account, are currently excluded from rate base in the per books COSS.

[2] Projected updates to the Federal and NC tax EDIT during 2019 by Tax
Smith Exhibit 4, Page 3, Line 1 return accruals on deferred revenues in the 0229010 account projected through 2/29/2020.

[3] Annual amortization for Federal EDIT-Protected from Tax department, estimated based on ARAM method.

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Smith Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	47.00%	4.15%	1.50%
Equity	53.00%	10.30%	5.46%
			6.96%
Statutory Tax Rate			23.17%
Retention factor for NCUC Fee, Uncollectibles			99.63%

Annual Rider Calculation

Amortization - From Page 1, L11

Year		Beginning Balance, Page 1, L8 (A)	Federal EDIT - Protected (B)	Federal EDIT - Unprotected, PP&E related (C)	Federal EDIT - Unprotected, non PP&E related (D)	NC EDIT (E)	Deferred Revenue (F)	Total Amortization (G) =(B)+(C)+(D)+[E]+[F]	Ending Balance before Return (H) = (A) - (G)	Average of Beginning and Ending Balance (I) = ((A) + (H)) /2	EDIT Balance in Base Rates, Page 1, L1 (J)	Change in Regulatory Liability for Rider Return (K) = (I) - (J)	Return for Rider (L) = (K) x After Tax WACC	Rider Revenues (M) = (G) + (L)	Rider Revenues NCUC Fee, Uncollectibles (N) = (M) / Retention Factor
Sep 20- Nov 21	1	(1,310,833)	(31,642)	(16,335)	(15,910)	(4,745)	(55,157)	(123,790)	(1,187,044)	($1,248,939)	(1,200,485)	($48,453)	($3,372)	(127,162)	(127,633)
Dec 21- Nov 22	2	(1,187,044)	(31,642)	(16,335)	(15,910)	(4,745)	(55,157)	(123,790)	(1,063,254)	($1,125,149)	(1,200,485)	$75,336	$5,243	(118,547)	(118,986) [1]
Dec 22- Nov 23	3	(1,063,254)	(31,642)	(16,335)	(15,910)	(4,745)	-	(68,632)	(994,622)	($1,028,938)	(1,200,485)	$171,547	$11,938	(56,694)	(56,904) [1]
Dec 23- Nov 24	4	(994,622)	(31,642)	(16,335)	(15,910)	(4,745)	-	(68,632)	(925,989)	($960,305)	(1,200,485)	$240,180	$16,715	(51,918)	(52,110) [1]
Dec 24- Nov 25	5	(925,989)	(31,642)	(16,335)	(15,910)	(4,745)	-	(68,632)	(857,357)	($891,673)	(1,200,485)	$308,812	$21,491	(47,141)	(47,316) [1]

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by September 30th for Commission approval.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL

	Deferred Revenue for Federal Tax Rate Change in account 0229010	NC Retail
1	Projected Changes in Deferred Revenue for Federal Tax Rate Change through Feb 2020	($1,923,073)

I/A

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
Regulatory Asset and Liability Rider
For the test period ended December 31, 2018
(Thousands of Dollars)

SMITH
Exhibit No. 5

Line No.	Description		NC RETAIL	Reference
1	Net Over Amortization	$	(2,090,713)	Smith Exhibit 5, page 2
2				
3	kWh sales		38,687,267,513	Pirro Exhibit 8
4				
5	$ per kWh	$	(0.00005)	Line 1 / Line 3

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
Regulatory Asset and Liability Rider
For the test period ended December 31, 2018

NC RETAIL
Schedule of Expired amortizations which were continued

Line No.	Date	EPA Emmission Procees	Gain on Harris Land	DOE Refund	Over Amortization Asset	Wayne	Over Amortization Liability	Net Over Amortization
1	Apr-18					(577,821)	(577,821)	(577,821)
2	May					(577,821)	(1,155,642)	(1,155,642)
3	Jun	207,218	128,287		335,504	(577,821)	(1,733,463)	(1,397,959)
4	Jul	208,333	128,287		672,125	(577,821)	(2,311,284)	(1,639,159)
5	Aug	208,333	128,287		1,008,745	(577,821)	(2,889,105)	(1,880,360)
6	Sep	208,333	128,287	212,423	1,557,788	(577,821)	(3,466,926)	(1,909,138)
7	Oct	208,333	128,287	212,423	2,106,831	(577,821)	(4,044,747)	(1,937,916)
8	Nov	208,333	128,287	212,423	2,655,874	(577,821)	(4,622,568)	(1,966,694)
9	Dec	208,333	128,287	212,423	3,204,917	(577,821)	(5,200,389)	(1,995,472)
10	Jan-19	208,333	128,287	212,423	3,753,961	(577,821)	(5,778,210)	(2,024,249)
11	Feb	208,333	(11,837)	212,423	4,162,880	(577,821)	(6,356,031)	(2,193,151)
12	Mar	208,333	128,287	212,423	4,711,923	(577,821)	(6,933,852)	(2,221,929)
13	Apr	208,333	128,287	212,423	5,260,967	(577,821)	(7,511,673)	(2,250,706)
14	May	208,333	128,287	212,423	5,810,010	(577,821)	(8,089,494)	(2,279,484)
15	Jun	208,333	128,287	212,423	6,359,053	(577,821)	(8,667,315)	(2,308,262)
16	Jul	208,333	128,287	212,423	6,908,096	(577,821)	(9,245,136)	(2,337,040)
17	Aug	208,333	128,287	212,423	7,457,139	(577,821)	(9,822,957)	(2,365,818)
18	Sep	208,333	128,287	212,423	8,006,182	(577,821)	(10,400,778)	(2,394,596)
19	Oct	208,333	128,287	212,423	8,555,226	(577,821)	(10,978,599)	(2,423,373)
20	Nov	208,333	128,287	212,423	9,104,269	(577,821)	(11,556,420)	(2,452,151)
21	Dec	208,333	128,287	212,423	9,653,312	(577,821)	(12,134,241)	(2,480,929)
22	Jan-20	208,333	128,287	212,423	10,202,355	(577,821)	(12,712,062)	(2,509,707)
23	Feb	208,333	128,287	212,423	10,751,398	(577,821)	(13,289,883)	(2,538,485)
24	Mar	208,333	128,287	212,423	11,300,441	(577,821)	(13,867,704)	(2,567,263)
25	Apr	208,333	128,287	212,423	11,849,484	(577,821)	(14,445,525)	(2,596,041)
26	May	208,333	128,287	212,423	12,398,528	(577,821)	(15,023,346)	(2,624,818)
27	Jun	208,333	128,287	212,423	12,947,571	(577,821)	(15,601,167)	(2,653,596)
28	Jul	208,333	128,287	212,423	13,496,614	(577,821)	(16,178,988)	(2,682,374)
29	Aug	208,333	128,287	212,423	14,045,657	(577,821)	(16,756,809)	(2,711,152)
30	Total	5,623,884	3,323,621	5,098,152	14,045,657	(16,756,809)	(16,756,809)	(2,711,152)
31								
32								
33							Total NC Retail liability to amortize	(2,711,152)
34							Statutory tax rate	23.1693% [1]
35							Retention factor for NCUC Fee, Uncollectibles	99.6309% [2]
36							Year 1 Revenue Requirement	**(2,090,713)**

[1] NC-0104 - 2018 Calculation of Tax Rate, Line 10
[2] Adjusted for NC-0103 Regulatory Fee and NC-0105 Uncollectibles Rate

SMITH
Supplemental Exhibit 1
Page 1

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (a) (Col. 1)		North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)		Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)		After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,682,421		$ 3,657,503	$ (296,495)		$ 3,361,009	$ 534,344		$ 3,895,353
	Electric operating expenses:									
	Operation and maintenance:									
2	Fuel used in electric generation	1,429,144		881,642	(29,976)		851,667			851,667
3	Purchased power	390,677		158,763	(1,965)		156,798			156,798
4	Other operation and maintenance expense	1,546,719		1,050,819	(187,389)		863,429	1,973		865,403
5	Depreciation and amortization	1,060,260		669,787	280,272		950,060			950,060
6	General taxes	153,362		102,197	309		102,506			102,506
7	Interest on customer deposits	8,643	(b)	7,971	-		7,971			7,971
8	Net income taxes	150,622		112,986	(65,445)		47,541	123,040		170,581
9	Amortization of investment tax credit	(3,356)		(2,134)	(1,481)		(3,614)			(3,614)
10	Total electric operating expenses	4,736,071		2,982,032	(5,674)		2,976,358	125,013		3,101,371
11	Operating income	$ 946,351		$ 675,472	$ (290,821)		$ 384,651	$ 409,331		$ 793,982
12	Original cost rate base	$ 14,580,739		$ 9,859,050	$ 785,755	(d)	$ 10,644,806	$ 67,827	(f)	$ 10,712,632
13	Rate of return on North Carolina retail rate base			6.85%			3.61%			7.41%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

SMITH
Supplemental Exhibit 1
Page 1

I/A

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

					North Carolina Retail Operations					
					Before Proposed Increase			After Proposed Increase		
Line No.	Description		Dec. 31, 2018 Amount	Pro forma Ratio	Retail Rate Base	Embedded Cost/ Return %	Operating Income	Retail Rate Base	Embedded Cost/ Return %	Operating Income
			(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)
1	Long-term debt		$ 8,108,191	47.00%	$ 5,003,059	4.15%	$ 207,855	$ 5,034,937	4.15%	$ 209,179
2	Members' equity	(a)	8,717,931	53.00%	5,641,747	3.13%	176,796	5,677,695	10.30%	584,803
3	Total		$ 16,826,122	100.00%	$ 10,644,806 (b)		$ 384,651 (c)	$ 10,712,632 (b)		793,982
4	Operating income before increase (Line 3, Column 5)									384,651
5	Additional operating income required (Line 3 minus Line 4)									409,331
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue									(307)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)									125,320
8	Additional revenue requirement									$ 534,344
9	Revenue Adjustments	(d)								$ (120,837)
10	Net Increase									$ 413,507

-- Some totals may not foot or compute due to rounding.

Notes: (a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

SMITH
Supplemental Exhibit 1
Page 2

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Electric Operating Revenue	Fuel Used in Electric Generation	Purchased Power	Other O&M Expense	Depreciation and Amortization	General Taxes	Income Taxes 23.1693%	Amortization of ITC	Operating Income
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)
1	Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	(52,114)	-	(172,813)
1B	Annualize retail revenues for current rates - Supplemental (E)	24,093	-	-	89	-	-	5,562	-	18,443
2	Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	3,304	-	10,955
2B	Update fuel costs to proposed rate - Supplemental (E)	-	24,023	-	-	1,684	-	(5,956)	-	(19,751)
3 *	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	(13,653)	-	(45,273)
3B	Normalize for weather - Supplemental (E)	4,882	(2,252)	-	18	-	-	1,649	-	5,467
4 *	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	534	-	1,771
4B	Annualize revenues for customer growth - Supplemental (E)	(7,341)	(5,328)	-	(27)	-	-	(460)	-	(1,526)
5	Eliminate unbilled revenues	11,826	-	-	-	-	-	2,740	-	9,086
6	Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	63,161	-	128,547
6B	Adjust for costs recovered through non-fuel riders - Supplemental (E)	-	-	-	(31)	-	-	7	-	24
7	Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	556	-	1,843
8	Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	(9,747)	(1,481)	(30,841)
8B	Annualize depreciation on year end plant balances - Supplemental (E)	-	-	-	-	(661)	-	153	-	508
9	Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	(942)	-	(3,122)
10 *	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	(17,857)	-	(59,213)
10B	Adjust for post test year additions to plant in service - Supplemental (E)	-	-	-	-	(8,630)	(1,637)	2,379	-	7,888
11 *	Amortize deferred environmental costs	-	-	-	-	105,972	-	(24,553)	-	(81,419)
11B	Amortize deferred environmental costs - Supplemental (E)	-	-	-	-	(9,949)	-	2,305	-	7,644
12	Annualize O&M non-labor expenses	-	-	-	1,311	-	-	(304)	-	(1,007)
12B	Annualize O&M non-labor expenses - Supplemental (E)	-	-	-	8	-	-	(2)	-	(6)
13 *	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	4,542	-	15,060
13B	Normalize O&M labor expenses - Supplemental (E)	-	-	-	(1,282)	-	(72)	314	-	1,040
14	Update benefits costs	-	-	-	(3,060)	-	-	709	-	2,351
14B	Update benefits costs - Supplemental (E)	-	-	-	(3,298)	-	-	764	-	2,534
15 *	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	1,444	-	4,788
15B	Levelize nuclear refueling outage costs - Supplemental (E)	-	-	-	42	-	-	(10)	-	(32)
16 *	Amortize rate case costs	-	-	-	701	-	-	(162)	-	(539)
16B	Amortize rate case costs - Supplemental (E)	-	-	-	-	-	-	-	-	-
17	Adjust aviation expenses	-	-	-	(1,452)	-	(18)	341	-	1,129
18	Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	434	-	1,438
19 *	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	988	-	3,276
19B	Adjust for Merger Related Costs - Supplemental (E)	-	-	-	-	(10)	-	2	-	8

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes 23.1693% (Col. 7)	Amortization of ITC (Col. 8)	Operating Income (Col. 9)
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	5,414	-	17,952
20B		Amortize Severance Costs - Supplemental (E)	-	-	-	(774)	-	-	179	-	594
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	(2,183)	-	2,183
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	123	-	(123)
22B		Synchronize interest expense with end of period rate base - Supplemental (E)	-	-	-	-	-	-	663	-	(663)
23	*	Adjust cash working capital	-	-	-	-	-	-	122	-	(122)
23B		Adjust cash working capital - Supplemental (E)	-	-	-	-	-	-	(27)	-	27
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-
24B		Adjust coal inventory - Supplemental (E)	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	(1,204)	-	(3,993)
25B		Adjust for credit card fees - Supplemental (E)	-	-	-	110	-	-	(26)	-	(85)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	(20,760)	-	(68,841)
26B		Adjust Depreciation for new rates - Supplemental (E)	-	-	-	-	(873)	-	202	-	671
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	21	-	70
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	(10,129)	-	(33,588)
29B		Update deferred balance and amortize storm costs - Supplemental (E)	-	-	-	-	(516)	-	120	-	397
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	1,767	-	5,859
32B		Reflect retirement of Asheville Steam Generating Plant - Supplemental (E)	-	-	-	-	(123)	-	29	-	95
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	(1,144)	-	(3,794)
33B		Adjust for CertainTeed payment obligation - Supplemental (E)	-	-	-	(4,939)	-	-	1,144	-	3,794
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	(4,565)	-	(15,138)
34B		Amortize deferred balance Asheville Combined Cycle - Supplemental (E)	-	-	-	-	(2,018)	-	468	-	1,550
35		Adjust Purchased Power	-	-	(1,965)	-	-	-	455	-	1,510
36		Correct Lead Lag	-	-	-	-	-	-	-	-	-
37		Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ (74,904)	$ (1,481)	$ (319,441)
37B		Changes in Supplemental	21,635	16,443	-	(10,083)	(21,096)	(1,709)	9,460	-	28,620
38		Total adjustments	$ (296,495)	$ (29,976)	$ (1,965)	$ (187,389)	$ 280,272	$ 309	$ (65,445)	$ (1,481)	$ (290,821)

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

SMITH
Supplemental Exhibit 1
Page 3
(continued)

I/A

SMITH
Supplemental Exhibit 1
Page 3 (continued)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	224,927	-	224,927
1		Annualize retail revenues for current rates - Supplemental (E)	-	-	-	-	-	-	-	-	(24,005)	-	(24,005)
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,258)	-	(14,258)
2B		Update fuel costs to proposed rate - Supplemental (E)	-	-	-	-	-	-	-	-	25,707	-	25,707
3	*	Normalize for weather	-	-	-	-	-	-	-	-	58,926	-	58,926
3B		Normalize for weather - Supplemental (E)	-	-	-	-	-	-	-	-	(7,116)	-	(7,116)
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,306)	-	(2,306)
4B		Annualize revenues for customer growth - Supplemental (E)	-	-	-	-	-	-	-	-	1,986	-	1,986
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,826)	-	(11,826)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,313)	(94,010)	(261,323)
6B		Adjust for costs recovered through non-fuel riders - Supplemental (E)	-	-	-	-	-	-	-	-	(31)	-	(31)
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,399)	-	(2,399)
8		Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,141	-	40,141
8B		Annualize depreciation on year end plant balances - Supplemental (E)	-	-	-	-	-	-	-	-	(661)	-	(661)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,064	-	4,064
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,070	120,182	197,252
10B		Adjust for post test year additions to plant in service - Supplemental (E)	(401,540)	255,631	-	20,220	(25,293)	-	-	(150,982)	(10,266)	(13,676)	(23,942)
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	105,972	29,499	135,471
11B		Amortize deferred environmental costs - Supplemental (E)	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,949)	(2,769)	(12,718)
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,311	-	1,311
12B		Annualize O&M non-labor expenses - Supplemental (E)	-	-	-	-	-	-	-	-	8	-	8
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,602)	-	(19,602)
13B		Normalize O&M labor expenses - Supplemental (E)	-	-	-	-	-	-	-	-	(1,354)	-	(1,354)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,060)	-	(3,060)
14B		Update benefits costs - Supplemental (E)	-	-	-	-	-	-	-	-	(3,298)	-	(3,298)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,232)	-	(6,232)
15B		Levelize nuclear refueling outage costs - Supplemental (E)	-	-	-	-	-	-	-	-	42	-	42
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	701	186	887
16B		Amortize rate case costs - Supplemental (E)	-	-	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,470)	-	(1,470)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,871)	(5,835)	(7,707)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,264)	31	(4,232)
19B		Adjust for Merger Related Costs - Supplemental (E)	(460)	9	-	-	-	-	-	(451)	(10)	(41)	(51)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

SMITH
Supplemental Exhibit 1
Page 3 (continued)

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
20 *	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,366)	1,621	(21,745)
20B	Amortize Severance Costs - Supplemental (E)	-	-	-	(1,538)	356	-	-	(1,182)	(774)	(107)	(881)
21	Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,841)	-	(2,841)
22 *	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22B	Synchronize interest expense with end of period rate base - Supplemental (E)	-	-	-	-	-	-	-	-	863	-	863
23 *	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	159	(2,447)	(2,288)
23B	Adjust cash working capital - Supplemental (E)	-	-	-	5,868	-	-	-	5,868	(35)	532	497
24	Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24B	Adjust coal inventory - Supplemental (E)	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,924)	(1,924)
25 *	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,197	-	5,197
25B	Adjust for credit card fees - Supplemental (E)	-	-	-	-	-	-	-	-	110	-	110
26	Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,601	(8,037)	81,564
26B	Adjust Depreciation for new rates - Supplemental (E)	-	-	-	-	-	-	-	-	(873)	-	(873)
27	Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,757	-	5,757
28	Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
29 *	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,717	42,594	86,311
29B	Update deferred balance and amortize storm costs - Supplemental (E)	-	-	-	(7,227)	1,675	-	-	(5,553)	(516)	(503)	(1,019)
30	Adjust other revenue	-	-	-	-	-	-	-	-	4,150	-	4,150
31	Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(234)	-	(234)
32 *	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,626)	(2,965)	(10,591)
32B	Reflect retirement of Asheville Steam Generating Plant - Supplemental (E)	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	(123)	6,819	6,695
33	Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,939	-	4,939
33B	Adjust for CertainTeed payment obligation - Supplemental (E)	-	-	-	-	-	-	-	-	(4,939)	-	(4,939)
34 *	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,703	2,230	21,933
34B	Amortize deferred balance Asheville Combined Cycle - Supplemental (E)	-	-	(248)	(4,036)	935	-	-	(3,349)	(2,018)	(303)	(2,321)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,965)	-	(1,965)
36	Correct Lead Lag	-	-	-	(8,580)	-	-	-	(8,580)	-	(777)	(777)
37	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 415,773	$ 83,923	$ 499,696
37B	Changes in Supplemental	(114,948)	44,968	(21,565)	(36,428)	(12,796)	-	-	(140,769)	(37,251)	(12,751)	(50,002)
38	Total adjustments	$ 465,611	$ (57,480)	$ (172,644)	$ 855,279	$ (202,080)	$ -	$ (102,930)	$ 785,755	$ 378,522	$ 71,173	$ 449,694

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

SMITH
Supplemental
Exhibit 1
Page 3
(continued)

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 465,611	$ 19,271,521
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(57,480)	(8,099,540)
3	Net electric plant		16,126,825	10,763,851	408,130	11,171,982
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	855,279	480,107
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(202,080)	(1,534,708)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 785,755	$ 10,644,806

-- Some totals may not foot or compute due to rounding.

SMITH
Supplemental Exhibit 1
Page 4

I/A

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (164,173)	$ 9,892,347
2	Transmission Plant	2,746,389	1,643,263	156,769	1,800,032
3	Distribution Plant	6,944,764	6,052,263	406,303	6,458,565
4	General Plant	628,616	465,435	44,615	510,050
5	Intangible Plant	527,370	358,178	49,459	407,638
6	Subtotal	27,398,830	18,575,658	492,974	19,068,632
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 465,611	$ 19,271,521

-- Some totals may not foot or compute due to rounding.

SMITH
Supplemental Exhibit 1
Page 4a

I/A

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (19,814)	$ (4,410,572)
2	Transmission Reserve	(816,198)	(488,611)	(26,088)	(514,699)
3	Distribution Reserve	(3,235,148)	(2,819,386)	27,615	(2,791,771)
4	General Reserve	(167,536)	(124,045)	(16,254)	(140,300)
5	Intangible Reserve	(322,831)	(219,260)	(22,938)	(242,198)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (57,480)	$ (8,099,540)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

SMITH
Supplemental Exhibit 1
Page 4b

I/A

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

SMITH
Supplemental Exhibit 1
Page 4c

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations: Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(29,725)	(b)	130,416	67,827	(c)	198,243
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		885,004		447,714	-		447,714
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		855,279		596,695	67,827		664,522
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 855,279		$ 480,107	$ 67,827		$ 547,934

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

SMITH
Supplemental Exhibit 1
Page 4d

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018

NC-0100
Supplemental
January Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma represents the additional North Carolina retail revenues, uncollectible expense, and regulatory fees required to reflect the annualization of rates in effect on January 1, 2019. The pro forma also removes Demand Side Management/Energy Efficiency (DSM/EE) and the Joint Agency Acquisition Rider (JAAR) from the annualized revenues. In addition, fuel is neutralized in the case through this adjustment and the fuel pro forma adjustment.

The impact to O&M expenses for uncollectible expense and the NCUC fee is determined by multiplying the impact to revenue by the uncollectible rate and the NCUC assessment rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

January Update

NC-0102 revised for approved fuel rates under Docket E2 Sub 1204

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0100
Supplemental
January Update

Line No.	Description	Source	Total NC Retail January	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue	NC-0101	$ (201,667)	$ (225,760)	$ 24,093
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.	NC-0101	(744)	(833)	89
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-0101	(46,552)	(52,114)	5,562
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(47,297)	(52,947)	5,651
18					
19	Operating income	L4 - L17	$ (154,370)	$ (172,813)	$ 18,443
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0101
Supplemental
January Update

Line No.	Description	Per Book Total NC Retail		Present Total NC Retail		Present vs. Per Book	
		Col. (a)		Col. (b)		Col. (c)	
1	Revenues to be Collected in Proposed Rates						
2	Retail Sales (Billed Revenues)	$ 3,563,165	[1]	$ 3,256,953	[1]	$ (306,212)	
3	Provision for Rate Refund	(104,546)	[5]			104,546	
4		$ 3,458,620		$ 3,256,953		$ (201,667)	
5							
6	Uncollectible (booked to O&M)					0.2394%	[2]
7	NCUC Fee (booked to O&M)					0.1297%	[3]
8	Impact to O&M - NCUC fee (L2 x L4)					$ (744)	
9							
10	Taxable income (L4 - L8)					$ (200,922)	
11	Statutory tax rate					23.1693%	[4]
12	Impact to income taxes (L12 x L13)					$ (46,552)	
13							
14	Impact to operating income (L12 - L14)					$ (154,370)	

[1] NC-0102 - Billed Revenues and Present Revenues Annualized, Line 43
[2] NC-0105 Uncollectible rate
[3] NC-0103 rate effective July 1, 2019
[4] NC-0104 - 2017 Tax Rate, Line 10
[5] NC-0106 - 2018 Provision for Rate Refund

Note: some totals may not foot or compute due to rounding.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
North Carolina Revenue Annualization Adjustment
For the test period ended December 31, 2018

NC-0102
Supplemental
January Update

	(a)	(b)	(c)	(d)	(e)
		Per Book Test Year Revenues (As Billed)	**Current Revenue, Excluding DSM and EE Riders**	**Revenue Annualization & Rider Adjustment**	**NCUC utility assessment fee and Uncollectible**
		Per CIM Report RMC1Y	*Per Tariff Worksheets*	*(c) - (b)*	
	Rate Class/Schedule				
1	**Residential**	$ 1,820,227,901	$ 1,671,008,906	$ (149,218,994)	$ (362,691)
2	RES	1,772,700,825	1,627,945,892	(144,754,933)	(351,841)
3	R-TOUD	41,429,999	37,486,504	(3,943,495)	(9,585)
4	R-TOU	6,097,077	5,576,511	(520,566)	(1,265)
5					
6	**Small General Service (SGS)**	$ 226,009,560	$ 210,976,543	$ (15,033,017)	$ (36,539)
7	SGS	225,577,034	210,568,831	(15,008,204)	(36,479)
8	SGS-TOUE	432,526	407,712	(24,813)	(60)
9					
10	**SGS-TOU Constant Load (SGS-TOU-CLR)**	$ 3,781,169	$ 3,539,804	$ (241,365)	$ (587)
11					
12	**Medium General Service**	$ 886,079,172	$ 807,833,140	$ (78,246,032)	$ (190,184)
13	MGS	271,655,277	242,144,278	(29,511,000)	(71,729)
14	SGS-TOU	611,317,514	562,838,889	(48,478,625)	(117,832)
15	GS-TES	1,510,948	1,345,435	(165,513)	(402)
16	APH-TES	138,228	133,640	(4,589)	(11)
17	CH-TOUE	1,244,444	1,173,027	(71,417)	(174)
18	CSE	208,132	193,536	(14,596)	(35)
19	CSG	4,629	4,336	(293)	(1)
20					
21	**Large General Service**	$ 532,588,876	$ 469,674,111	$ (62,914,766)	$ (152,920)
22	LGS	89,684,567	79,639,686	(10,044,881)	(24,415)
23	LGS-TOU	442,904,310	390,034,425	(52,869,885)	(128,505)
24					
25	**Large General Service breaking out RTP**	$ 532,588,876	$ 469,674,111	$ (62,914,766)	$ (152,920)
26	LGS excl RTP	88,859,666	79,000,414	(9,859,252)	(23,964)
27	LGS-TOU excl RTP	113,958,528	100,616,525	(13,342,003)	(32,429)
28	LGS-RTP, LGS-TOU RTP	329,770,682	290,057,172	(39,713,511)	(96,527)
29					
30	**Seasonal and Intermittent Service**	$ 5,200,515	$ 4,715,715	$ (484,800)	$ (1,178)
31					
32	**Traffic Signal Service (TSS)**	$ 454,335	$ 434,956	$ (19,379)	$ (47)
33	TSS	419,358	400,209	(19,149)	(47)
34	TFS	34,977	34,747	(230)	(1)
35					
36	**Outdoor Lighting**	$ 88,623,085	$ 88,567,631	$ (55,454)	$ (135)
37	ALS	62,444,191	62,316,881	(127,310)	(309)
38	SLS	20,222,208	20,268,793	46,586	113
39	SLR	5,956,686	5,981,956	25,270	61
40					
41	**Sports Field Lighting Service**	$ 200,691	$ 202,072	$ 1,381	$ 3
42					
43	**North Carolina Retail Tariff Revenue**	$ 3,563,165,305	$ 3,256,952,878	$ (306,212,426)	$ (744,278)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018

NC-0103
Supplemental
January Update

NCUC Statutory Regulatory Fee Percentage Rate

Line No.	Rate	Description
1	0.1300%	Current statutory regulatory fee percentage rate
2	99.7606%	1 less current uncollectibles rate on NC-0105
3	0.1297%	Adjusted statutory regulatory fee percentage rate *(excluding uncollectibles rate)*

Docket M-100 Sub 142

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. M-100, SUB 142

Section (a) of N.C.G.S. § 62-302 provides that the amount of the reserve may not exceed one-half of the cost of operating the Commission and the Public Staff as reflected in the certified budget for the previous fiscal year.

At present, the Commission's regulatory fee for noncompetitive jurisdictional revenues is 0.14%. Pursuant to N.C.G.S. § 62-302(b)(3), the Commission has reviewed the estimated cost of operating the Commission and the Public Staff for the next fiscal year, including the reserve margin permitted under N.C.G.S. § 62-302(a), and has determined that the regulatory fee for noncompetitive jurisdictional revenues should be decreased to 0.13%, effective July 1, 2019.

IT IS, THEREFORE, ORDERED as follows:

1. That the regulatory fee for noncompetitive jurisdictional revenues shall be, and is hereby, set at 0.13%, effective July 1, 2019.

2. That the Chief Clerk shall serve this Order on all utilities regulated by the Commission.

ISSUED BY ORDER OF THE COMMISSION.

This the 18th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

Regulatory Fee Reporting

The regulatory fee legislation for public utilities and electric membership corporations was enacted by the North Carolina General Assembly to provide funding to pay the expenses incurred by the Commission and Public Staff in regulating public utilities in the interest of the using and consuming public. The regulatory fee requirements are administered in compliance with G.S. 62-302.

The Commission's Fiscal Management Division is responsible for the collection, deposit, accounting, and reporting of the regulatory fee for the Commission.

G.S. 62-302 and Commission Rule R-15 state in part that: "The regulatory fee imposed under this section is due and payable to the Commission on or before the 15th day of the second month following the end of each quarter. Each public utility subject to the regulatory fee shall on or before the date the fee is due for each quarter, prepare and render a report on a form prescribed by the Commission."

**** Effective July 1, 2018, the Regulatory Fee Percentage Rate will remain at 0.14% (0.0014) for state fiscal year 2018-2019. The two rates for the telephone subsection (h) and (m) companies will remain the same as .04% (.0004) and .02% (.0002) respectively. With the rate not changing, there will not be another Order issued.**

For assistance you can contact the following individuals in Regulatory Fees Reporting:

- Regina Williams at 919-733-5265 or email at rwilliams@ncuc.net
- Terreca Ettson at 919-715-0442 or email at tettson@ncuc.net

Also, you can contact the Fiscal Management Section at 919-733-7680 or email Fiscal Management at fiscalmanagement@ncuc.net.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018

NC-0104
Supplemental
January Update

2019 Calculation of Tax Rates

Current (Statutory) and Deferred Tax Rate Per "Provision" - Year 2018

Line No.	Description	Total	Statutory Rate	Allocation Factor	Composite Rate
1			(a)	(b)	(a) x (b)
2		100.0000%			
3	North Carolina	2.1160%	2.5000%	84.6380%	2.1160%
4	South Carolina	0.6300%	5.0000%	12.6000%	0.6300%
5	Federal Taxable Income (L2 - L3 - L4)	97.2541%			
6	Federal Tax Rate	21.0000%			
7	Federal Net of State (L5 x L6)	20.4234%			
8	North Carolina (L3)	2.1160%			
9	South Carolina (L4)	0.6300%			
10	Composite Tax Rate (L7 + L8 + L9)	23.1693%			

Source: Duke Energy Tax Department

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018

NC-0105
Supplemental
January Update

Development of Uncollectibles Rate

Line No.	Description	Source	Amount	
1	Uncollectibles Expense (904)	*Trial Balance*	10,008,548	
2	Retail rate revenue (440 - 445)	*Trial Balance*	4,181,118,687	[1]
3	Uncollectibles Rate	*Row 1 / Row 2*	0.2394%	

[1] FERC Accounts 440-445, excluding Unbilled Revenue

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update Annualize Retail revenues for current rates
For the test period ended December 31, 2018

NC-0106
Supplemental
January Update

Provision for Rate Refund

Line No.	Description	Account		Total System			Total NC Retail	
1	Tax Reform Provision for Rate Refund	0449111	$	*(112,908,671)*	[1]	$	(98,495,765)	[2]
2	Tax Reform - Riders	0449115		*(6,050,000)*	[1]		(6,050,000)	[2]
3			$	*(118,958,671)*		$	(104,545,765)	

[1] E-1 Item 2, Trial Balance
[2] E-1 Item 45, Cost of Service

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0200
Supplemental
January Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts fuel expense,depreciation expense and income taxes for fuel clause expense during the test period to match the fuel clause revenues derived from the fuel factor approved by the Commission in Docket No. E-2, Sub 1173. By matching the expenses to the revenue, this adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related expenses that are recoverable through the fuel clause. This adjustment also eliminates the deferred fuel expense from the test period.

The impact to fuel and fuel related expenses is determined as follows:
1. The total fuel clause expense allocated in cost of service is eliminated from the test period.

2. The pro forma fuel clause expense is calculated by multiplying the NC Retail kWh sales for the test period by the most recent approved fuel rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

November Update
Revised for approved rates under Docket E2 Sub 1204

December Update
Removed effect of approved rates under Docket E2 Sub 1204. Will update along side Revenue impact in NC-0100 for Supplemental filing

January Update
Revised for approved rates under Docket E2 Sub 1204 and change in treatment of Catalyst Depreciation

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0200
Supplemental
January Update

Line No.	Description	Source	Total NC Retail		
1			January	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation	NC-0201	11,449	(12,574)	24,023
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization	NC-0201	-	(1,684)	1,684
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-0201	(2,653)	3,304	(5,956)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	8,796	(10,955)	19,751
18					
19	Operating income	L4 - L17	$ (8,796)	$ 10,955	$ (19,751)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service				
29	Accumulated depreciation and amortization				
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies				
34	Working capital investment				
35					
36					
37	Less:				
38	Accumulated deferred taxes				
39	Operating reserves				
40					
41					
42	Construction work in progress				
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0201
Supplemental
January Update

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	SI NCSI	Area Service Lighting NCALS	Sports Field Lighting Service NCSFL	Street Lighting Service NCSLS	Street Lighting Service NCSLR	Traffic Service Signal NCTSS		Total NC Retail	
1	Fuel Clause Expense and Deferred Fuel Expense Allocated in Per Books Cost of Service													
2	Remove fuel included in system average fuel costs												$ 729,766	[1]
3	Remove purchased power included in system average fuel costs - demand												41,843	[2]
4	Remove purchased power included in system average fuel costs - energy												322,567	[3]
5	Remove reagents & by-products included in system average fuel costs												62,778	[4]
6	Remove catalyst depreciation included in system average fuel costs												-	[5]
7	Remove 0557980 - Retail Deferred Fuel Expenses												(273,901)	[6]
8	Total Fuel Clause Expense Allocated in COS and Retail Deferred Fuel Expense (Sum L2 through L7)												$ 883,053	
9														
10	Fuel Clause Expense to Add (Based on Approved Fuel Rates)													
11	Average fuel rate billed in test period	2.238	2.188	2.305	2.449	2.305	1.780	1.780	1.780	1.780	2.188	[7]		
12	Increment in Fuel Filing, excluding Reg Fee & EMF (Cents/kWh) (L13 - L11)	0.088	0.312	0.151	(0.395)	0.151	0.437	0.437	0.437	0.437	0.312			
13	Approved Base Fuel Factor (Cents/kWh), excluding Regulatory Fee	2.326	2.499	2.456	2.054	2.456	2.217	2.217	2.217	2.217	2.499	[7]		
14														
15	NC Retail kWh actual sales - 12 months ended December 2018	16,666,046,589	1,982,596,401	11,178,964,878	8,457,791,022	43,075,313	267,795,639	1,134,908	85,107,971		4,754,792	[8]	38,687,267,513	[8]
16														
17	Adjusted Fuel Clause Expenses (L15 x (L13 / 100,000))	$ 387,652	$ 49,545	$ 274,555	$ 173,723	$ 1,058	$ 5,937	$ 25	$ 1,887	$ -	$ 119		894,502	
18														
19	Impact to fuel (-L2 + L17)												$ 164,736	
20														
21	Impact to purchased power (-L3 - L4 - L7)												$ (90,509)	
22														
23	Impact to Energy Related O&M (-L5)												$ (62,778)	
24														
25	Impact to depreciation and amortization (-L6)												$ -	
26														
27	Taxable income (-L19 - L21 - L23 - L25)												$ (11,449)	
28	Statutory tax rate												23.1693%	[9]
29	Impact to income taxes (L27 x L28)												$ (2,653)	
30	Impact to operating income (L27 - L29)												$ (8,796)	

[1] E-1 Item 45A, Cost of Service Factor E1All
[2] E-1 Item 45A, Cost of Service Factor E1All
[3] E-1 Item 45A, Cost of Service Factor E1All
[4] E-1 Item 45A, Cost of Service Factor E1All
[5] Catalyst adjusted through Depreciation proformas NC-0800 and NC-2600
[6] E-1 Item 45A, Cost of Service, Direct Assigned to NC Retail then Allocated using Factor E2ALL
[7] NC-0202 - NC Billed Fuel Factors, Line 5 and Line 8
[8] NC-0404 - NC Billed KWH Sales
[9] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202
Supplemental
January Update

NC Billed Fuel Factors (with EMF and EMF Interest Increment/Decrement for approved cost factors)

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	Area Service Lighting	Sports Field Lighting Service	Street Lighting Service	Traffic Service Signal	
1										
2	Approved net fuel and fuel related costs factors (including EMF)									
3	January 2018 through November 2018 fuel rate billed	2.179	2.121	2.258	2.417	1.657	1.657	1.657	2.121	[1]
4	December 2018 fuel rate billed	2.886	2.919	2.820	2.795	3.136	3.136	3.136	2.919	[2]
5	Average fuel rate billed in test period (Monthly Weighted Avg L3 and L4)	2.238	2.188	2.305	2.449	1.780	1.780	1.780	2.188	
6										
7	Approved net fuel and fuel related costs factors (excluding EMF)									
8	Approved net fuel and fuel related costs factors (pro forma fuel factor)	2.326	2.499	2.456	2.054	2.217	2.217	2.217	2.499	[3]
9										
10	Increase (Decrease) in fuel rate (L8 - L5)	0.088	0.312	0.151	(0.395)	0.437	0.437	0.437	0.312	

[1] NC-0202-1 - Docket No. E-2, Sub 1146, Appendix A, Column F
[2] NC-0202-2 - Docket No. E-2, Sub 1173, Appendix A, Column F
[3] NC-0202-3- Approved rates in Docket No. E-2, Sub 1173

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202-1
Supplemental
January Update

Approved Fuel Rates for December 2017 through November 2018

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC	)	ORDER APPROVING
Pursuant to G.S. 62-133.2 and	)	FUEL CHARGE
NCUC Rule R8-55 Relating to Fuel	)	ADJUSTMENT
and Fuel-Related Charge Adjustments	)	
for Electric Utilities	)	

HEARD: Tuesday, September 19, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	3.013	(0.834)	2.179	-	-	2.179
Small General Service	3.001	(0.880)	2.121	-	-	2.121
Medium General Service	2.921	(0.565)	2.356	(0.084)	(0.014)	2.258
Large General Service	2.958	(0.541)	2.417	-	-	2.417
Lighting	3.655	(1.998)	1.657	-	-	1.657

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202-2
Supplemental
January Update

Approved Fuel Rates for December 2018 through November 2019

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1173

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities

) ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, September 18, 2018, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	1.993	0.318	2.311	0.575	-	2.886
Small General Service	2.088	0.468	2.556	0.363	-	2.919
Medium General Service	2.431	0.046	2.477	0.343	-	2.820
Large General Service	2.253	(0.496)	1.757	1.038	-	2.795
Lighting	0.596	1.655	2.251	0.885	-	3.136

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202-3
Supplemental
January Update

Approved Fuel Rates for December 2019 through November 2020

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Fuel & Fuel Related Costs, Excl. Purch Capacity	2.188	2.344	2.333	1.975	2.216
Renewable & QF Purch Capacity	0.138	0.155	0.123	0.079	0.001
Total Adjusted Fuel and Fuel Related Costs	2.326	2.499	2.456	2.054	2.217
EMF	0.373	0.198	0.218	0.648	0.530
EMF Interest	-	-	-	-	-
Net Proposed Fuel and Fuel Related Cost Factors	2.699	2.697	2.674	2.702	2.747

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0203
Supplemental
January Update

Monthly Fuel Filing-System Average Fuel Costs for 12 Months Ended December 2018

As of 1/30/19 **Schedule 2**

Duke Energy Progress
Details of Fuel and Fuel-Related Costs

Docket No. E-2, Sub 1164

Description	December 2018	12 Months Ended December 2018
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 34,453,367	$ 307,900,875
0501310 fuel oil consumed - steam	1,404,117	10,490,738
Total Steam Generation - Account 501	35,857,484	318,391,613
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	16,323,865	184,163,880
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	18,456,887	185,884,718
0547000 natural gas consumed - Combined Cycle	54,365,629	649,230,756
0547106 biogas consumed - Combined Cycle	44,669	179,596
0547200 fuel oil consumed	1,051,520	63,615,887
Total Other Generation - Account 547	73,918,705	898,910,957
Reagents		
Catalyst Depreciation	131,225	2,737,099
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	2,048,497	17,128,899
Total Reagents	2,179,721	19,865,998
By-products		
Net proceeds from sale of by-products	72,561,504	85,600,935
Total By-products	72,561,504	85,600,935
Total Fossil and Nuclear Fuel Expenses		
Included in Base Fuel Component	200,841,279	1,506,933,383
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	636,198	26,295,307
Capacity component of purchased power (renewables)	1,413,993	42,177,805
Fuel and fuel-related component of purchased power	28,818,399	527,852,191
Total Purchased Power and Net Interchange - Account 555	30,868,590	596,325,303
Less fuel and fuel-related costs recovered through intersystem sales - Account 447	28,778,413	207,269,136
Total Fuel and Fuel-Related Costs	$ 202,931,456	$ 1,895,989,550

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize for weather
For the test period ended December 31, 2018

NC-0300
Supplemental
February Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma reflects adjustments to revenue, fuel expense, operation and maintenance expense, and income taxes to normalize weather conditions experienced during the test period.

The impact to revenue is determined as follows:
1. The percentage of NC Retail kWh sales for the test period is calculated by dividing NC Retail kWh sales by Retail kWh sales.

2. The NC Retail kWh weather adjustment for the test period is determined by multiplying the percentage of NC Retail kWh sales by the Retail kWh weather adjustment. This Retail kWh weather adjustment is calculated by determining the effect that temperature variances have on kWh sales and then pricing out that change in kWh sales for each customer class during the test period at the rates in effect during the test period.

The weather normals used in deriving the temperature corrections for the year 2018 reflect a 30-year average of heating and cooling degree days/hours. The derivations of the individual monthly weather normals start with calculating the simple average of the hourly temperatures from the following five weather stations:

1. Asheville Regional Airport, WBAN: 03812
2. Columbia Metropolitan Airport, WBAN: 13883
3. Wilmington International Airport, WBAN: 13748
4. Raleigh-Durham International Airport, WBAN: 13722
5. Fayetteville Regional Airport/Grannis Field, WBAN: 93740

WBAN *: Weather Bureau Army Navy station identifier from NOAA's National Climatic Data Center*

Next, degree hours are calculated by taking the average hourly temperatures and subtracting them from a base of 65-degree Fahrenheit. Finally, they are summed for each day to determine the daily heating or cooling degree hours and then summed again over the billing period.

3. The average price by class for the test period is calculated by dividing NC Retail revenue (dollars in thousands) by NC Retail kWh sales.

4. The weather adjusted revenue for the test period is calculated by multiplying the NC Retail kWh weather adjustment by the average price by class.

The impact to fuel expense is determined by multiplying the NC Retail kWh weather adjustment by the most recent approved fuel rate.

The impact to other operation and maintenance expense is determined by multiplying the impact to revenue by the statutory regulatory fee percentage rate and the uncollectibles rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October Update
2018 weather impacts were updated with 2 additional months of sales and weather data

November Update
2018 weather impacts were updated with an additional month of sales and weather data

December Update
2018 weather impacts were updated with an additional month of sales and weather data

January Update
2018 weather impacts were updated with an additional month of sales and weather data

February Update
2018 weather impacts were updated with an additional month of sales and weather data. NC-0301 adjusted to use present revenues annualized excluding Basic Customer Charge. NC-0303 adjusted to reflect NC Retail.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize for weather
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0300
Supplemental
February Update

Line No.	Description	Source	Total NC Retail		
			February	Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue	NC-0301	$ (72,510)	$ (77,392)	$ 4,882
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation	NC-0301	(20,432)	(18,180)	(2,252)
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-0301	(268)	(286)	18
11	Depreciation and amortization		-	-	-
12	General taxes	NC-0301	-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-0301	(12,004)	(13,653)	1,649
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(32,704)	(32,119)	(585)
18					
19	Operating income	L4 - L17	$ (39,806)	$ (45,273)	$ 5,467
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize for weather
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0301
Supplemental
February Update

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service		Total	
1	Retail kWh weather adjustment	(628,587,507)	(34,426,443)	(162,787,434)	(46,375,228)	[2]	(872,176,612)	
2								
3	NC Retail kWh sales - per book	16,666,046,589	1,982,596,401	11,178,964,878	8,457,791,022	[1]	38,285,398,890	
4	NC Retail revenue	1,468,522	172,878	793,060	468,984	[3]	$ 2,903,444	
5	Average price by class in ¢/kWh (L4 / L3) x 100,000	8.811	8.720	7.094	5.545			
6								
7	Weather adjusted revenue (L1 x L5) / 100,000	$ (55,388)	$ (3,002)	$ (11,548)	$ (2,572)		$ (72,510)	
8								
9	Fuel and fuel related costs ¢/kWh (excluding EMF)	2.326	2.499	2.456	2.054	[4]		
10	Impact to fuel (L1 x L9) / 100,000	$ (14,621)	$ (860)	$ (3,998)	$ (953)		$ (20,432)	
11								
12	NC Retail revenue weather adjustment, net of fuel (L7 - L10)	$ (40,767)	$ (2,142)	$ (7,550)	$ (1,619)		$ (52,078)	
13								
14	Calculation of NCUC Regulatory Fee							
15	Uncollectibles Rate	0.2394%	0.2394%	0.2394%	0.2394%		0.2394%	[5]
16	Statutory regulatory fee percentage rate	0.1297%	0.1297%	0.1297%	0.1297%		0.1297%	[6]
17	Impact to O&M (L7 x (L15 + L16)	$ (204.42)	$ (11.08)	$ (42.62)	$ (9.49)		$ (268)	
18								
19	Taxable income (L12 - L17)	$ (40,562)	$ (2,131)	$ (7,508)	$ (1,609)		$ (51,810)	
20	Statutory tax rate	23.1693%	23.1693%	23.1693%	23.1693%	[6]	23.1693%	[7]
21	Impact to income taxes (L19 x L20)	$ (9,398)	$ (494)	$ (1,740)	$ (373)		$ (12,004)	
22	Impact to operating income (L19 - L21)	$ (31,164)	$ (1,637)	$ (5,768)	$ (1,237)		$ (39,806)	

[1] NC-0302 - 2018 KWH Sales - Per Book [excluding Lighting and General and Industial includes HP kWhs]
[2] NC-0303 - KWH Weather Normalizations - Based on 30-Year Average, Line 13
[3] NC-0404 - Present Revenues Excluding Basic Customer Charge - North Carolina Retail
[4] NC-0202 - NC Billed Fuel Factors (with EMF and EMF Interest Increment/Decrement for approved cost factors), Line 8
[5] NC-0105 - 2018 Uncollectibles Rate, Line 4
[6] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate - Adjusted, Docket No. M-100, Sub 142, Line 3
[7] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize for weather
For the test period ended December 31, 2018

NC-0302
Supplemental
February Update

Billed Revenue and KWH Sales - Excluding REPS, DERP and Account 0444000 - Public St and Highway Lighting

Source: Customer Information System

			State								
			North Carolina			South Carolina			Total Sum of		Total Sum of
1	COS Category	Description	Sum of KWH		Sum of REVENUE	Sum of KWH		Sum of REVENUE	KWH		REVENUE
2	Residential	RES - RESIDENTIAL SERVICE	16,158,859,096		1,772,700,800	2,148,532,519		252,526,648	18,307,391,615		2,025,227,448
3		R-TOUD - RESIDENTIAL SERVICE TIME-OF-USE	451,040,840		43,402,895	41,479,049		4,263,168	492,519,889		47,666,063
4		R-TOU - RESIDENTIAL SERVICE TIME-OF-USE	56,146,653		4,124,181	-		-	56,146,653		4,124,181
5	**Residential Sum**		**16,666,046,589**	**$**	**1,820,227,876**	**2,190,011,568**	**$**	**256,789,816**	**18,856,058,157**	**$**	**2,077,017,692**
6	Small General Service	GS - GENERAL SERVICE				3,679,279		484,079	3,679,279		484,079
7		SGS - SMALL GENERAL SERVICE	1,950,982,004		226,009,560	275,256,804		34,675,435	2,226,238,808		260,684,995
8		SGS-TOU-CLR - SMALL GENERAL SERVICE TIME-OF-USE CONSTANT LOAD RATE	31,614,397		3,781,169	4,439,514		446,421	36,053,911		4,227,590
9	**Small General Service Sum**		**1,982,596,401**	**$**	**229,790,729**	**283,375,597**	**$**	**35,605,935**	**2,265,971,998**	**$**	**265,396,664**
10	Medium General Service	APH-TES - AGRICULTURAL POST-HARVEST SERVICE	2,065,800		138,228				2,065,800		138,228
11		CH-TOUE - CHURCH SERVICE EXPERIMENTAL TIME-OF-USE	8,706,511		1,244,444				8,706,511		1,244,444
12		CSE - CHURCH AND SCHOOL SERVICE	1,373,440		208,133	1,312,020		186,473	2,685,460		394,606
13		CSG - CHURCH AND SCHOOL SERVICE	25,680		4,629	25,120		4,764	50,800		9,393
14		MGS - MEDIUM GENERAL SERVICE	2,773,108,650		271,655,277	536,499,774		59,483,621	3,309,608,424		331,138,898
15		SGS-TES - SMALL GENERAL SERVICE THERMAL ENERGY STORAGE	21,819,600		1,510,948	See attached			21,819,600		1,510,948
16		SGS-TOU - SMALL GENERAL SERVICE TIME-OF-USE	8,371,865,197		611,317,514	1,115,225,685		88,508,538	9,487,090,882		699,826,052
17	**Medium General Service Sum**		**11,178,964,878**	**$**	**886,079,173**	**1,653,062,599**	**$**	**148,183,396**	**12,832,027,477**	**$**	**1,034,262,569**
18	Large General Service	LGS - LARGE GENERAL SERVICE	1,141,204,433		88,859,666	698,027,189		50,318,321	1,839,231,622		139,177,987
19		LGS-CRTL-TOU - LARGE GENERAL SERVICE CURTAILMENT TIME-OF-USE (SPECIAL)				702,376,100		30,077,028	702,376,100		30,077,028
20		LGS-RTP - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING)	9,861,252		824,900	-		-	9,861,252		824,900
21		LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	5,708,044,202		328,945,782	571,293,865		32,059,629	6,279,338,067		361,005,411
22		LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	1,598,681,135		113,958,528	309,355,839		19,236,422	1,908,036,974		133,194,950
23	**Large General Service Sum**		**8,457,791,022**	**$**	**532,588,876**	**2,281,052,993**	**$**	**131,691,400**	**10,738,844,015**	**$**	**664,280,276**
24	Seasonal Intermittent	SI - SEASONAL OR INTERMITTENT SERVICE	43,075,313		5,200,515	18,492,882		2,335,235	61,568,195		7,535,750
25	**Seasonal Intermittent Sum**		**43,075,313**	**$**	**5,200,515**	**18,492,882**	**$**	**2,335,235**	**61,568,195**	**$**	**7,535,750**
26	Other	ALS - AREA LIGHTING SERVICE	267,795,639		62,444,191	63,427,856		14,298,726	331,223,495		76,742,917
27		SFLS - SPORTS FIELD LIGHTING SERVICE	1,134,908		200,691	149,692		40,747	1,284,600		241,438
28		SLS - STREET LIGHTING SERVICE	85,107,971		26,178,894	16,316,405		4,211,648	101,424,376		30,390,542
29		TSS - TRAFFIC SIGNAL SERVICE	4,754,792		454,335	855,613		77,478	5,610,405		531,813
30	**Other Sum**		**358,793,310**	**$**	**89,278,111**	**80,749,566**	**$**	**18,628,599**	**439,542,876**	**$**	**107,906,710**
	Grand Total		**38,687,267,513**	**$**	**3,563,165,280**	**6,506,745,205**	**$**	**593,234,381**	**45,194,012,718**	**$**	**4,156,399,661**

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize for weather
For the test period ended December 31, 2018

NC-0303
Supplemental
February Update

NC RETAIL

kWh Weather Normalizations - Based on 30-Year Average (1988-2017)

Line No.	Month		Residential	Small General Service	Medium General Service	Large General Service	Area Service Lighting	Sports Field Lighting Service	Street Lighting Service	Traffic Service Signal	Total Retail
30 Year Average [1][2]											
1	Jan	2018	(278,658,213)	(5,893,390)	(29,771,915)	(12,827,354)					(327,150,871)
2	Feb	2018	222,671,001	470,721	2,182,899	1,470,945					226,795,566
3	Mar	2018	163,296,262	131,090	13,683,444	51,950,276					229,061,072
4	Apr	2018	(87,087,913)	(57,207)	(5,971,318)	(19,647,751)					(112,764,188)
5	May	2018	(23,709,064)	(1,244,701)	(8,451,338)	(9,908,272)					(43,313,374)
6	Jun	2018	(161,317,843)	(12,020,047)	(58,812,601)	(23,126,012)					(255,276,502)
7	Jul	2018	(81,363,561)	(4,983,950)	(39,078,666)	(60,989,871)					(186,416,048)
8	Aug	2018	21,448,558	1,556,201	8,136,808	5,201,498					36,343,066
9	Sep	2018	(112,082,617)	4,557,680	41,203,972	63,633,695					(2,687,270)
10	Oct	2018	(196,026,292)	(17,143,037)	(95,818,564)	(66,596,083)					(375,583,977)
11	Nov	2018	(6,824,725)	(18,540,270)	(94,988,229)	(47,894,882)					(168,248,106)
12	Dec	2018	(88,933,101)	18,740,465	104,898,075	72,358,582					107,064,021
13	Total		(628,587,507)	(34,426,443)	(162,787,434)	(46,375,228)	-	-	-	-	(872,176,612)

[1] Duke Energy Load Forecasting
[2] Excludes Public Street Lighting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0400
Supplemental
February Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma annualizes revenue, fuel expense, operation and maintenance expense, and income taxes to reflect changes in the number of customers and usage per customer during the test period.

The impact to revenue was determined as follows:

To determine the additional revenue requirement resulting from customer growth, the monthly increase in number of customers was multiplied by the applicable average monthly kWh consumption per customer to derive the annualized change in kWh consumption based on the number of customers at the end of the test period.

The impact to fuel expense was determined by multiplying the 'Customer growth adjustment to KWH sales - NC kWh adjustment' by the most recent approved fuel rate (excluding EMF).

The impact to other operation and maintenance expense is determined by multiplying the impact to revenue by the statutory regulatory fee percentage rate and the uncollectibles rate.

The impact to income taxes was determined by multiplying taxable income by the statutory tax rate.

This adjustment updates revenues to reflect customer growth experienced beyond the test period, through July 2019. The underlying calculations reflect the same methods used in the Company's rebuttal testimony as explained by Company Witness Pirro in Docket E-2 Sub 1142.

October update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through October 2019

November update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through November 2019

December update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through December 2019
NC-0404 was adjusted to calculate Residential ¢ / kWh excluding the Basic Customer Charge

January update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through January 2019

February update
NC-0402 and NC-0403 now reflect separate adjustments for Customer Growth and Usage
Updated NC-0403 for weather impacts in NC-300 and customer growth information through February 2019.
NC-0404 was adjusted to reflect the ¢ / kWh both with and excluding the Basic Customer Charge

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0400
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Application	Change
1			February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue	NC-0401	$ (2,159)	$ 5,182	(7,341)
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation	NC-0401	(2,471)	2,857	(5,328)
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-0401	(8)	19	(27)
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-0401	74	534	(460)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(2,405)	3,411	(5,815)
18					
19	Operating income	L4 - L17	$ 246	$ 1,771	$ (1,526)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0401
Supplemental
February Update

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	SI NCSI	Area Service Lighting	Sports Field Lighting Service NCSFL	Street Lighting Service NCSLS	Traffic Service Signal NCTSS	Total NC Retail	
1												
2	Customer growth and usage Revenue adjustment	$ 9,029	$ (3,886)	$ (10,755)	$ 3,466	$ (321)	$ -	$ 19	$ 299	$ (10)	$ (2,159)	[1]
3												
4	Approved fuel and fuel related costs ¢/kWh (excluding EMF)	2.326	2.499	2.456	2.054	2.456	2.217	2.217	2.217	2.499		[2]
5	Customer growth and usage adjustment to kWh sales	57,867,175	(51,924,021)	(147,449,173)	56,502,116	(3,240,014)	-	109,168	967,947	(113,275)	(87,280,077)	[1]
6	Impact to fuel (L4 x (L5 / 100,000))	$ 1,346	$ (1,298)	$ (3,621)	$ 1,161	$ (80)	$ -	$ 2	$ 21	$ (3)	$ (2,471)	
7												
8	Calculation of NCUC Regulatory Fee and Uncollectible											
9	Uncollectible rate	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	[3]
10	Statutory regulatory fee percentage rate	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	[4]
11	Impact to O&M ((L9 + L10) x L2)	$ 33	$ (14)	$ (40)	$ 13	$ (1)	$ -	$ 0	$ 1	$ (0)	$ (8)	
12												
13	Taxable income (L2 - L6 - L11)	$ 7,650	$ (2,574)	$ (7,094)	$ 2,292	$ (240)	$ -	$ 17	$ 276	$ (7)	$ 320	
14												
15	Statutory tax rate	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	[5]
16	Impact to income taxes (L13 x L15)	$ 1,772	$ (596)	$ (1,644)	$ 531	$ (56)	$ -	$ 4	$ 64	$ (2)	$ 74	
17												
18	Impact to operating income (L13 - L16)	$ 5,878	$ (1,977)	$ (5,451)	$ 1,761	$ (184)	$ -	$ 13	$ 212	$ (6)	$ 246	

[1] NC-0402 - Calculation of Customer Growth and Usage Revenue Adjustment
[2] NC-0202 - NC Billed Fuel Factors (with EMF and EMF Interest Increment/Decrement for approved cost factors), Line 8
[3] NC-0105 - 2018 Uncollectibles Rate, Line 4
[4] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate - Adjusted, Docket No. M-100, Sub 142, Line 3
[5] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0402a
Supplemental
February Update

Calculation of Customer Growth Adjustment

Line No.	Rate Schedule	NC Retail KWH Adjustment (a)	[1]	Cents Per kWh (b)	[2]	Revenue Adjustment (c) = ((a) x (b) / 100,000)
1	Residential	455,478,398		8.85		$ 40,300
2	Residential excl. TOU	446,771,841		8.85		39,543
3	Residential TOU	8,706,557		8.70		757
4						
5	Small General Service	28,622,184		10.83		$ 3,099
6	SGS excl. Constant Load Rate	27,586,206		10.81		2,983
7	SGS Constant Load Rate	1,035,978		11.20		116
8						
9	Medium General and Seasonal and Intermittent Service	146,119,738		7.66		$ 11,191
10	Medium General Service excl. Time of Use	61,472,997		8.73		5,368
11	Medium General Service Time of Use	81,504,976		6.72		5,480
12	Seasonal and Intermittent Service	3,141,764		10.95		344
13						
14	Large General Service	23,110,768		6.14		$ 1,420
15	Large General Service excl. Time of Use and Real Time Pricin	6,988,823		6.92		484
16	Large General Service Time of Use	9,609,632		6.29		605
17	Large General Service Real Time Pricing	6,512,313		5.08		331
18						
19	Sports Field Lighting Service	80,635		17.81		14
20	Street Lighting Service	1,677,242		30.84		517
21	Traffic Signal Service	(103,515)		9.15		(9)
22						
23	Total kWh Adjustment (L1 through L21)	654,985,450				
24						
25						
26	NC Residential Change in number of customers	# of Customers	[3]	BCC	[4]	
27	Residential	272,550		$ 14.00		$ 3,816
28	Residential TOU	5,562		$ 16.85		$ 94
29						
30						60,442

[1] NC-0403 - Customer Growth Adjustment to KWH Sales, col (d)
[2] NC-0404 - Present Revenue Annualized and KWH Sales - NC Retail, c/kWh. Residential uses ¢ / kWh excluding BCC.
[3] Source Rate Design Regression Analysis
[4] Basic Customer Charge per Tariffs - Pirro Exhibit 1: RES-60 $14.00, R-TOU-60 $16.85, and R-TOUD-60 $16.85

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0402b
Supplemental
February Update

Calculation of Customer Usage Revenue Adjustment

Line No.	Rate Schedule	NC Retail KWH Adjustment (a)	[1]	Cents Per kWh (b)	[2]	Revenue Adjustment (c) = ((a) x (b) / 100,000)
1	Residential	(397,611,223)		8.85		$ (35,180)
2	Residential excl. TOU	(390,010,808)		8.85		(34,519)
3	Residential TOU	(7,600,415)		8.70		(661)
4						
5	Small General Service	(80,546,205)		8.67		$ (6,985)
6	SGS excl. Constant Load Rate	(77,630,841)		8.76		(6,799)
7	SGS Constant Load Rate	(2,915,364)		6.39		(186)
8						
9	Medium General and Seasonal and Intermittent Service	(296,808,924)		7.50		$ (22,267)
10	Medium General Service excl. Time of Use	(124,868,375)		8.53		(10,651)
11	Medium General Service Time of Use	(165,558,772)		6.61		(10,952)
12	Seasonal and Intermittent Service	(6,381,778)		10.42		(665)
13						
14	Large General Service	33,391,348		6.13		$ 2,046
15	Large General Service excl. Time of Use and Real Time Pricin(	10,097,727		6.90		697
16	Large General Service Time of Use	13,884,375		6.28		871
17	Large General Service Real Time Pricing	9,409,246		5.08		478
18						
19	Sports Field Lighting Service	28,533		17.81		5
20	Street Lighting Service	(709,295)		30.84		(219)
21	Traffic Signal Service	(9,760)		9.15		(1)
22						
23	Total kWh Adjustment (L1 through L21)	(742,265,526)				(62,601)

[1] NC-0403 - Customer Growth Adjustment to KWH Sales, col (d)
[2] NC-0404 - Present Revenue Annualized and KWH Sales - NC Retail, c/kWh. Residential uses ¢ / kWh excluding BCC.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0403
Supplemental
February Update

Customer Growth Adjustment to KWH Sales

Line No.	(a) Rate Schedule	(b) COS Category	(c) NC Proposed Customer Growth kWh Adjustment	(d) NC Proposed Change in Usage kWh Adjustment	(e) NC Proposed KWH Adjustment [1]		(f) Adj by COS Schedule	(f) Adj by COS Schedule	COS Schedules	(g) Service Bases 12/31/2018 C1ALL Allocator [2]	
1											
2	NC Residential	Residential	455,478,398	(397,611,223)	57,867,175	RES, RET	446,771,841	(390,010,808)	NCRES	NCRES	1,177,050
3							8,706,557	(7,600,415)	NCRET	NCRET	22,938
4	NC General:									NCSGS	160,062
5	General Service Small	Small General Service	28,622,184	(80,546,205)	(51,924,021)	SGS, SGSTCLR	27,586,206	(77,630,841)	NCSGS	NCSGSTCLR	6,011
6	General Service Medium	Medium General Service	146,119,738	(296,808,924)	(150,689,187)	MGS, SGS-TOU,SI	1,035,978	(2,915,364)	NCSGSTCLR	NCSGTM	22,077
7	Total General		174,741,922	(377,355,130)	(202,613,208)		81,504,976	(165,558,772)	NCSGTM	NCMGS	16,651
8							61,472,997	(124,868,375)	NCMGS	NCSI	851
9							3,141,764	(6,381,778)	NCSI	NCLGS	88
10	NC Lighting:									NCLGT	121
11	Street Lighting	Lighting	1,677,242	(709,295)	967,947	SLS/SLR	1,677,242	(709,295)	NCSLS	NCRTP	82
12	Sports Field Lighting	Lighting	80,635	28,533	109,168	SFLS	80,635	28,533	NCSFL	NCTSS	780
13	Traffic Signal Service	Lighting	(103,515)	(9,760)	(113,275)	TSS/TFS	(103,515)	(9,760)	NCTSS	NCALS	0
14	Total Street Lighting		1,654,362	(690,521)	963,841					NCSLS	1,578
15										NCSFL	78
16	NC Industrial:										1,408,367
17	I - Textile	Large General Service	-	-	-		6,988,823	10,097,727	NCLGS		
18	I - Nontextile	Large General Service	23,110,768	-	23,110,768	LGS incl. TOU & RTP	9,609,632	13,884,375	NCLGT		
19	I - Textile & Nontextile	Large General Service	-	33,391,348	33,391,348		6,512,313	9,409,246	NCRTP		
20	Total Industrial		23,110,768	33,391,348	56,502,116						
21											
22							654,985,450	(742,265,526)			
23	Total		654,985,450	(742,265,526)	(87,280,077)						

Notes:
[1] Information provided by Rate Design.
[2] Regression using number of service bases, and schedules in proposed adjustment per Rate Design

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0404
Supplemental
February Update

Present Revenue Annualized and KWH Sales - NC Retail

Line No.	COS Category	Description	NORTH CAROLINA RETAIL Present Revenue Annualized [1]	Basic Customer Charge (BCC)	Present Revenue Excluding BCC	Per Book kWh Sales [2]	All-Inclusive ¢ / kWh	w/o BCC ¢ / kWh
1								
2	Residential	RES - RESIDENTIAL SERVICE	$ 1,627,945,892	$ (197,751,086)	$ 1,430,194,806	16,158,859,096	10.07	8.85
3		R-TOUD - RESIDENTIAL SERVICE TIME-OF-USE	37,486,504	(4,041,968)	33,444,536	451,040,840		
4		R-TOU - RESIDENTIAL SERVICE ALL-ENERGY TIME-OF-USE	5,576,511	(694,079)	4,882,432	56,146,653	9.93	8.70
5	**Residential Sum**		$ 1,671,008,906	$ (202,487,133)	$ 1,468,521,774	16,666,046,589		
6	Small General Service	SGS - SMALL GENERAL SERVICE	210,976,543	$ (40,117,843)	$ 170,858,700	1,950,982,004	10.81	8.76
7		SGS-TOU-CLR - SMALL GENERAL SERVICE TIME-OF-USE CONSTANT LOAD RATE	3,539,804	(1,520,432)	2,019,372	31,614,397	11.20	6.39
8	**Small General Service Sum**		$ 214,516,347	$ (41,638,275)	$ 172,878,072	1,982,596,401		
9	Medium General Service	APH-TES - AGRICULTURAL POST-HARVEST SERVICE	133,640	$ (1,281)	$ 132,359	2,065,800		
10		CH-TOUE - CHURCH SERVICE EXPERIMENTAL TIME-OF-USE	1,173,027	(95,984)	1,077,043	8,706,511		
11		CSE - CHURCH AND SCHOOL SERVICE	193,536	(14,938)	178,598	1,373,440		
12		CSG - CHURCH AND SCHOOL SERVICE	4,336	(342)	3,994	25,680		
13		MGS - MEDIUM GENERAL SERVICE	242,144,278	(5,603,638)	236,540,640	2,773,108,650	8.73	8.53
14		SGS-TES - SMALL GENERAL SERVICE THERMAL ENERGY STORAGE	1,345,435	(6,090)	1,339,345	21,819,600		
15		SGS-TOU - SMALL GENERAL SERVICE TIME-OF-USE	562,838,889	(9,050,665)	553,788,224	8,371,865,197	6.72	6.61
16	**Medium General Service Sum**		$ 807,833,140	$ (14,772,938)	$ 793,060,202	11,178,964,878		
17	Large General Service	LGS - LARGE GENERAL SERVICE	79,000,414	$ (219,986)	$ 78,780,428	1,141,204,433	6.92	6.90
18		LGS-RTP - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING)	-	-	-	9,861,252		
19		LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	290,057,172	(187,180)	289,869,991	5,708,044,202	5.08	5.08
20		LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	100,616,525	(283,320)	100,333,205	1,598,681,135	6.29	6.28
21	**Large General Service Sum**		$ 469,674,111	$ (690,486)	$ 468,983,624	8,457,791,022		
22	Other	ALS - AREA LIGHTING SERVICE	62,316,881	$ -	$ 62,316,881	267,795,639		
23		SFLS - SPORTS FIELD LIGHTING SERVICE	202,072	-	202,072	1,134,908	17.81	
24		SLS - STREET LIGHTING SERVICE	26,250,749	-	26,250,749	85,107,971	30.84	
25		TSS - TRAFFIC SIGNAL SERVICE	434,956	-	434,956	4,754,792	9.15	
26	**Other Sum**		$ 89,204,659	$ -	$ 89,204,659	358,793,310		
27	Seasonal Intermittent	SI - SEASONAL OR INTERMITTENT SERVICE	4,715,715	(228,386)	4,487,329	43,075,313	10.95	10.42
28	**Seasonal Intermittent Sum**		$ 4,715,715	$ (228,386)	$ 4,487,329	43,075,313		
29	Grand Total		$ 3,256,952,878	$ (259,817,218)	$ 2,997,135,660	38,687,267,513		

[1] NC-0102 - Column c
[2] NC-0302 Sum of kWh

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018

NC-0600
Supplemental
December Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts revenues and expenses to remove amounts that are associated with cost recovery through the following non-fuel riders: Renewable Energy Portfolio Standard Rider, Energy Efficiency Rider/DSM and DSDR Riders, the Joint Agency Asset Rider, EDIT Riders and the effects of HB 589. Rate base is also adjusted to eliminate the amounts recorded on the Company's financial statements as of December 31, 2018 related to these riders. The rate base adjustments are shown on Smith Exhibit 1, pages 4, 4a, 4b, 4c, and 4d.

December update

NC-0601 - Removed CPRE related O&M identified during internal review. GL reclass was recorded in December 2019.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0600
Supplemental
December Update

Line No.	Description	Source	Total NC Retail		
			December	Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue	NC-0601	$ (27,830)	$ (27,830)	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation	NC-0601	(18,522)	(18,522)	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-0601	(136,143)	(136,112)	(31)
11	Depreciation and amortization	NC-0601	(58,446)	(58,446)	-
12	General taxes	NC-0601	(6,458)	(6,458)	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-0601	63,168	63,161	7
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(156,401)	(156,377)	(24)
18					
19	Operating income	L4 - L17	$ 128,571	$ 128,547	$ 24
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-0601	$ (950,962)	$ (950,962)	$ -
29	Accumulated depreciation and amortization	NC-0601	158,734	158,734	-
30	Electric plant in service, net	Sum L28 through L29	(792,228)	(792,228)	-
31					
32	Add:				
33	Materials and supplies	NC-0601	(157,453)	(157,453)	-
34	Working capital investment	NC-0601	(150,987)	(150,987)	-
35	Nuclear Fuel	NC-0601	(27,363)	(27,363)	-
36					
37	Less:				
38	Accumulated deferred taxes	NC-0601	90,146	90,146	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (1,037,885)	$ (1,037,885)	$ -
45					
46	Note: Rate Base: positive number increases rate base / negative number decreases rate base				

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	(a) Description	(b) DSM/EE	(c) DSDR	(d) REPS	(e) JAAR	(f) HB 589	(g) EDIT	(h) Adjust Total System	(i) NC Retail Allocation [2]	(j) Total NC Retail	(k) Factor [2]
1											
2	Impact to Income Statement Line Items										
3	Electric operating revenue:										
4	Revenue	- [1]	- [1]	$ 24,719 [6]			- [1]	$ (24,719)	100.0000%	$ (24,719)	DA
5	Other Electric Revenues			1,114 [6]				(1,114)	100.0000%	(1,114)	DA
6	JAAR Revenue Adjustments				3,245 [7]			(3,245)	61.5278%	(1,996)	DPALL
7	Impact to revenue							$ (29,078)		$ (27,830)	
8											
9	Fuel used in electric generation:										
10	RECS Consumption Expense			18,424 [6]				$ (18,424)	100.0000%	$ (18,424)	DA
11	Biogas Expense			433				(433)	100.0000%	(433)	DA
12	REC Biogas Contra Expense			(333)				333	100.0000%	333	DA
13	REC Biogas Contra Expense - SC			(3)				3	100.0000%	3	DA
14	Impact to fuel							$ (18,522)		$ (18,522)	
15											
16											
17	Other operation and maintenance expense:										
18	O&M/A&G Expenses	88,956 [3]						$ (88,956)	81.0834%	$ (72,128)	DSMALL
19	Insurance Expense DSDR	707 [3]						(707)	67.9178%	(480)	PTDG
20	O&M recovered in JAAR				72,212 [7]			(72,212)	61.5278%	(44,431)	DPALL
21	A&G Related O&M recovered in JAAR				30,999 [7]			(30,999)	61.5278%	(19,073)	DPALL
22	CPRE O&M					37 [11]		(37)	83.9171%	(31)	RB_PLT_O_DI_OH_LN
23	Impact to O&M							$ (192,911)		$ (136,143)	
24											
25	Depreciation and amortization:										
26	DSDR Depreciation: Intangible Plant		1,158 [4]					$ (1,158)	67.9178%	$ (786)	PTDG
27	DSDR Depreciation: Transmission Plant		12 [4]					(12)	59.6699%	(7)	DTALL
28	DSDR Depreciation: Distribution Plant		4,306 [4]					(4,306)	87.1486%	(3,753)	RB_PLT_O_DI_
29	DSDR Depreciation: General Plant		855 [4]					(855)	74.0412%	(633)	RB_PLT_O_GN
30	DSM Allocated Amortizations	(38,327) [3]						38,327	81.0834%	31,077	DSMALL
31	DSM NC Amortizations	50,043 [3]						(50,043)	100.0000%	(50,043)	DA
32	DSM SC Amortizations	17,528 [3]						(17,528)	0.0000%	-	DA
33	REPS Rider NC Retail			6,514 [6]				(6,514)	100.0000%	(6,514)	DA
34	REPS Rider NC Wholesale			(26)				26	0.0000%	-	DA
35	JAAR Depreciation and amortization expense				$50,480 [7]			(50,480)	61.5278%	(31,059)	DPALL
36	EDIT Rider Amortization (Account 0407398)						($3,273) [9]	3,273	100.0000%	3,273	DA
37	Impact to depreciation and amortization							$ (89,270)		$ (58,446)	
38											
39	Property Tax										
40	Property Tax on DSDR		604 [3]					$ (604)	67.9178%	$ (410)	PTDG
41	Property Tax JAAR				6,087 [7]			(6,087)	61.5278%	(3,745)	DPALL
42	Impact to property tax							$ (6,691)		$ (4,155)	
43											
44	Other Tax										
45	Payroll Tax	275 [3]						$ (275)	81.0834%	$ (223)	DSMALL
46	Payroll Tax JAAR				3,380 [7]			(3,380)	61.5278%	(2,080)	DPALL
47	Impact to other tax							$ (3,655)		$ (2,303)	
48											
49	Taxable income (L7 - (L14 + L23 + L37 + L42 + L47))							$ 281,970		$ 191,739	
50	Statutory tax rate							23.1693%	[8]	23.1693% [8]	
51	Impact to income taxes (L49 x L50)							65,331		44,425	
52	EDIT Impact to Income Taxes						(18,743) [10]	18,743	100.0000%	18,743	DA
53	Total Tax impact (Sum L51 through L52)							$ 84,074		$ 63,168	
54											
55	Impact to operating income (L49 - L51)							$ 197,896		$ 128,571	

NC-0601
Page 1 of 2

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	DSM/EE	DSDR	REPS	JAAR	HB 589	EDIT	Adjust Total System	NC Retail Allocation [2]	Total NC Retail	Factor [2]
56	Impact to Rate Base Line Items										
57	Electric plant in service:										
58	DSDR Plant		215,855 [5]					$ (215,855)		$ (179,383)	Various
59	NCEMPA Plant Recovered in JAAR Rider				1,254,033 [7]			(1,254,033)	61.5278%	(771,579)	DPALL
60	Impact to electric plant in service							$ (1,469,888)		$ (950,962)	
61											
62	Accumulated depreciation and amortization:										
63	DSDR Accum Depr		(81,542) [5]					$ 81,542		$ 64,157	Various
64	NCEMPA Accum Depr revoered in JAAR Rider				(153,714) [7]			153,714	61.5278%	94,577	DPALL
65	Impact to accumulated depreciation							$ 235,256		$ 158,734	
66											
67	Nuclear Fuel										
68	JAAR Nuclear Fuel				44,473 [7]			$ (44,473)	61.5278%	$ (27,363)	DPALL
69											
70	Materials and supplies:										
71	Renewable Energy Credits (RECs)-NC			120,429 [6]				$ (120,429)	100.0000%	$ (120,429)	DA
72	JAAR Material and Supplies				60,175 [7]			(60,175)	61.5278%	(37,025)	DPALL
73											
74	Impact to Materials and Supplies							$ (180,604)		$ (157,453)	
75											
76	Working capital investment:										
77	REPS Incremental Costs			(2,911) [6]				$ 2,911	100.0000%	$ 2,911	DA
78	NC Solar Amort & Returns			58 [6]				(58)	100.0000%	(58.101)	DA
79	DSM/EE Regulatory Asset	219,774 [3]						(219,774)	100.0000%	(219,774)	DA
80	NC REC Liability - Retail			(114,256) [6]				114,256	100.0000%	114,256	DA
81	NC REC Liability - Wholesale			(31) [6]				31	0.0000%	-	DA
82	NC JAAR Reg Assets (Accts 0182479 and 0182485)				44,393 [9]			(44,393)	100.0000%	(44,393)	DA
83	CPRE Rider- Asset - Retail (Acct 0182528)					442 [9]		(442)	100.0000%	(442)	DA
84	Duke Generated REC Certificate			336 [6]				(336)	100.0000%	(335.739)	DA
85	NC Solar Rebate Program Costs - Retail			3,150 [6]				(3,150)	100.0000%	(3,150)	DA
86	Impact to working capital investment							$ (150,955)		$ (150,987)	
87											
88	Accumulated deferred income tax:										
89	ADIT on REPS Reg Asset and Liability									$ (26,325)	DA
90	ADIT on NC DSM/EE Reg Asset	(50,920) [3]								50,920	DA
91	ADIT on NC JAAR Reg Assets				(10,285)				100.0%	10,285	NB_PLT
92	ADIT on DSDR Plant		(27,051) [5]							22,481	Various
93	ADIT on JAAR: Production Plant related				(53,311) [7]				61.5278%	32,801	DPALL
94	ADIT on JAAR: Nuclear Fuel related				26 [7]				61.5278%	(16)	DPALL
95	ADIT on CPRE									102	DA
96											
97	Deferred tax rate									23.1693% [8]	
98	Total Impact to Accumulated deferred income tax (Sum L89 through L94)									$ 90,146	
99											
100											
101	Impact to rate base (L60 + L65 +L68+ L74 + L86 + L98)									$ (1,037,885)	

[1] Removed in Revenue Annualization adjustment NC-1000
[2] Allocation Factors - Direct Assign (DA); DSM (DSMALL), Gross Tangible Plant (PTDG), Production Demand (DPALL), Transmission Demand (DTALL), Gross Distribution Plant (RB_PLT_O_DI_), Gross General Plant (RB_PLT_O_GN), Gross Dist. Overhead Line Investment (RB_PLT_O_DI_OH_LN).
[3] NC-0602 - Detail DSM/EE DSDR Costs
[4] DSDR Depreciation Schedule from Accounting
[5] NC-0603 - DSDR support
[6] NC-0604 - Cost of Service REPS detail
[7] NC-0605 JAAR Support
[8] NC-0104 - 2018 Calculation of Tax Rate, Line 10
[9] E-1 Item 2, Trial Balance
[10] EDIT Rider Support - Tax Liability workpaper

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018

NC-0602
Supplemental
December Update

Remove DSM/EE/DSDR clause impacts

(a) Row	(b) Description	(c) FERC Account	(d) Sub Component of Account?	(e) Amount	
	INCOME STATEMENT				
	O&M				
1	OTHER EXPENSES - OPER	0557000	Y	$ 83,717,978	[1]
2	LOAD DISPATCH - DIST OF ELEC	0583100	Y	-	[1]
3	SUPERVSN AND ENGRING - DIST OPS	0580000	Y	-	[1]
4	MISC DISTRIBUTION EXP - OTHER	0588100	Y	2,200,556	[1]
5	MAINT OVERHD LINES - OTHER - DIST	0593000	Y	1,695,730	[1]
6	MAINT OF METERS - DIST	0597000	Y	-	[1]
7	ADVERTISING	0913001	Y	1,708	[1]
8	OFFICE EXPENSES	0921200	Y	576	[1]
9	EMPLOYEE BENEFITS - TRANSFERRED	0926600	Y	1,339,285	[1]
10	SubTotal O&M/A&G			88,955,833	
11	O&M Insurance on DSDR		Y	706,500	[2]
12	Total O&M/A&G			89,662,333	
13	Adjustment to Remove DSM/EE/DSDR O&M/A&G			$ (89,662,333)	
14					
15	**Depreciation**				
16	DSDR Annualized Depreciation Expense			6,330,487	[2]
17	Adjustment to remove Annualized Depreciation expense			$ (6,330,487)	
18					
19	**Deferrals/Amortizations**				
20	REG DEBIT - DSM/EE NC	0407358	N	$ 34,999,298	[3]
21	REG DEBIT- DSM/EE NC O&M	0407334	N	87,968,043	[3]
22	REG DEBIT - DSM/EE SC	0407359	N	5,253,766	[3]
23	REG DEBIT- DSM/EE SC O&M	0407335	N	24,436,376	[3]
24	DSM/EE O&M DEFERRAL/REG CREDIT NC	0407432	N	(72,924,432)	[3]
25	DSM/EE O&M DEFERRAL/REG CREDIT SC	0407433	N	(12,162,471)	[3]
26	DSM/EE CAPITAL DEFERRAL	0407414	N	(12,069,234)	[3]
27	REG CREDIT DSM/EE OTHER	0407416	N	(26,257,581)	[3]
28	Total Amortizations			$ 29,243,765	
29					
30	Adjustment to Remove DSM Amortizations - Allocated			$ 38,326,815	
31	Adjustment to Remove DSM Deferrals & Amortizations - D/A NCR			(50,042,909)	
32	Adjustment to Remove DSM Deferrals & Amortizations - D/A SCR			(17,527,671)	
33					
34	**Property taxes**				
35	PROPERTY TAX on DSDR		Y	603,872	[2]
36	Adjustment to Remove DSDR Property Taxes			$ (603,872)	
37					
38	**Other Taxes**				
39	PAYROLL TAX	0408960	Y	275,232	[1]
40	Adjustment to Remove DSM/EE/DSDR Other Taxes			$ (275,232)	
41					
42	**RATE BASE**				
43	**Reg Assets**				
44	NC DSM/EE DSDR DEFERRAL	0182381	N	$ 219,773,951	[3]
45	SC DSM/EE DSDR DEFERRAL	0182361	N	15,329,741	[3]
46	Total Reg Assets			$ 235,103,692	
47					
48	Adjustment to Remove DSM Reg Assets - D/A NCR			$ (219,773,951)	
49					
50	**ADIT**				
51	NC DSM/EE- ADIT	23.1693%	Y	$ (50,920,087)	
52	SC DSM/EE - ADIT	23.1693%	Y	(3,551,794)	
53	Total ADIT			$ (54,471,881)	
54					
55	Adjustment to Remove DSM ADIT - D/A NCR			$ 50,920,087	

Notes: DSM/EE revenues are removed in NC1000 - Annualize revenues for current rates, so not adjusted herein
DSDR Plant Assets and ADIT are removed in Adjustment NC - 0603
[1] ES-1 DSM/EE Recoverable O&M Costs by FERC Account
[2] DSM/EE Filing support - DSDR Deferral and Depreciation
[3] E-1 Item 2, Trial Balance

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018

NC-0603
Supplemental
December Update

Line No.	Description	Account	Total System		NC Retail Allocation	[2]	Total NC Retail
1	DSDR Plant						
2	Gross Plant balances:	Account					
3	Misc Intangible plant	303	$ 32,842,428	[1]	67.9178%		$ 22,305,852
4	Transmission Station Equip	353	607,005		59.6699%		362,199
5	Distribution - Structures and Improvements	361	9,396				
6	Distribution Station Equip	362	35,895,818				
7	Distribution Poles, Towers and Fixtures	364	20,010,140				
8	Distribution Overhead conductors and devices	365	45,606,682				
9	Distribution Underground conduit	366	1,255,885				
10	Distribution Underground conduit and devices	367	1,153,168				
11	Distribution Line transformers	368	52,270,623				
12	Distribution Services	369	1,302,785				
13	Distribution Meters	370	7,442,069				
14	Distribution Installs on customer premises	371	208,972				
15	Distribution Street lighting and signal systems	373	95,834				
16	Total Distribution Plant		$ 165,251,372		87.1486%		$ 144,014,208
17	General Plant - Structures and Improvements	390	115,689				
18	General Plant - Office furniture and equipment	391	2,378,696				
19	General Plant - Tools, shop and garage equipme	394	(8,272)				
20	General Plant - Communication equipment	397	14,667,883				
21	Total General Plant		17,153,997		74.0412%		12,701,020
22	Total Gross Plant in Service		$ 215,854,802				$ 179,383,279
23							
24	Accumulated Depreciation						
25	Misc Intangible plant	303	$ 32,430,895	[1]	67.9178%		$ 22,026,348
26	Transmission Station Equip	353	100,830		59.6699%		60,165
27	Distribution - Structures and Improvements	361	538				
28	Distribution Station Equip	362	5,116,227				
29	Distribution Poles, Towers and Fixtures	364	8,899,986				
30	Distribution Overhead conductors and devices	365	16,239,559				
31	Distribution Underground conduit	366	210,526				
32	Distribution Underground conduit and devices	367	237,789				
33	Distribution Line transformers	368	11,025,311				
34	Distribution Services	369	203,307				
35	Distribution Meters	370	2,121,797				
36	Distribution Installs on customer premises	371	45,863				
37	Distribution Street lighting and signal systems	373	19,030				
38	Total Distribution Plant		$ 44,119,932		87.1486%		$ 38,449,890
39	General Plant - Structures and Improvements	390	16,957				
40	General Plant - Office furniture and equipment	391	997,619				
41	General Plant - Tools, shop and garage equipme	394	(598)				
42	General Plant - Communication equipment	397	3,876,029				
43	Total General Plant		4,890,008		74.0412%		3,620,619
44	Total Accumulated Depreciation		$ 81,541,665				$ 64,157,022
45							
46	DSDR ADIT						$ 115,226,257
47	Intangible Plant related DSDR ADIT		$ (4,115,856)	[4]	67.9178%		$ (2,795,399)
48	Transmission Plant related DSDR ADIT		(77,248.17)	[4]	59.6699%		(46,094)
49	Distribution Plant related DSDR ADIT		(20,709,518.01)	[4]	87.1486%		(18,048,049)
50	General Plant related DSDR ADIT		(2,149,761)	[4]	74.0412%		(1,591,708)
51	Total DSDR ADIT		$ (27,051,206)	[3]			$ (22,481,250)
52							
53	[1] Accounting Smartgrid Depreciation Schedule						
54	[2] NC-0601						
55	[3] Tax Cumulative ADIT file						
56	[4] DSDR ADIT is allocated across plant categories based on gross plant:						
57	Intangible plant	15%	Line 3 / Line 22				
58	Transmission Plant	0%	Line 4+5 / Line 22				
59	Distribution Plant	77%	Line 16 / Line 22				
60	General Plant	8%	Line 21 / Line 22				
61		100%					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0604
Supplemental
December Update

Line No.				
1	**DEP REPS Collection by Customer Class**			
2		REPS Revenue	EMF	Total
3	Residential Certificates	$ 15,088,846	$ (6,682,636)	$ 8,406,210
4	Residential Incremental	456,674	(538,500)	(81,825)
5	Commercial Certificates	18,209,488	(3,432,136)	14,777,352
6	Commercial Incremental	544,685	(273,868)	270,817
7	Industrial Certificates	1,204,275	35,725	1,240,000
8	Industrial Incremental	34,994	2,421	37,415
9	Street Lighting Certificates	80,372	(15,261)	65,111
10	Street Lighting Incremental	2,342	(1,220)	1,121
11	Public Authority Certificates	2,654	85	2,740
12	Public Authority Incremental	74	7	81
13		$ 35,624,403	$ (10,905,381)	$ 24,719,022
14				
15	**REPS/RECs Expenses by FERC Account**			
16	Description	Account	REPS	COS Adj
17	**Income Statement**			
18	REPS Rider NC Retail	0407350	$ 1,547	$ 1,547
19	REPS Rider NC Whse	0407351	-	-
20	REPS Rider NC Retail-Cert	0407352	23,391	23,391
21	REPS Rider NC Whse-Cert	0407353	-	-
22	Int Exp On Revenue Refunds	0431710	182	182
23	Other Electric Revenues	0456610	1,114	1,114
24	NC Amort of Retail REC Exp	0407450	(18,424)	(18,424)
25	NC Amort of Whse REC Exp	0407451	(26)	(26)
26	RECS Consumption Expense	0509213	18,451	18,424
27	Biogas Expense	0547106	582	433
28	REC Biogas Contra Expense	0547107	(333)	(333)
29	REC Biogas Contra Expense - SC	0547108	(3)	(3)
30				
31	**Balance Sheet**			
32	RECs - DE Carolinas - NC	0158120	$ 120,429	
33	Prepaid Inv - Solar Recs	0165009	108	
34	REPS Incremental Costs	0182359	(2,911)	
35	NC Solar Amort & Returns	0182563	58	
36	Duke Generated REC Certificate	0182374	336	
37	NC Solar Rebate Program Costs	0182560	3,150	
38	NC REC Liability - Retail	0254250	(114,256)	
39	NC REC Liability - Whse	0254251	(31)	

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Eliminate costs recovered through non-fuel riders
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0605
Supplemental
December Update

Amounts Recovered through the Joint Agency Asset Rider

Line No.	Description		Total Utility	[1]
1	**Rate Base**			
2	Net PPE (Acquired and Capital Additions) - Accounts 101 and 108			
3	Gross PPE (including acquisition adjustment)	$	1,254,033	
4	Accumulated Depreciation/Amortization		(153,714)	
5				
6	Nuclear Fuel & Dry Cask Storage - Accounts 120.2 - 120.55		44,473	
7	Materials and Supplies Inventory - Account 154.1		60,175	
8				
9	Deferred Taxes			
10	- Property - Account 190/282		(53,311)	
11	- Nuclear Fuel - Account 190/282		26	
12				
13	**JAAR Revenue included in Revenue Requirement ***			
14	General Plant Return-Account 0454510	$	2,619	
15	Disptach Fee - Account 0456300		35	
16	Site Rep - Account 0456300		5	
17	Auxiliary Power - Account 0447150		502	
18	Return on coal inventory - Account 454XXX		84	
19	Total Test Period Revenue		3,245	
20				
21	**JAAR Operating Expenses included in Revenue Requirement ****			
22	O&M Expenses - Fossil - Accounts 0500-0514	$	5,953	
23	O&M Expenses - Nuclear - Accounts 0517-0532		66,259	
24	A&G Expenses - Account 929		30,999	
25	Total Test Period Expenses		103,211	
26				
27	**JAAR Payroll and Property Taxes included in Revenue Requirement**			
28	Payroll Tax - Account 0408151 & 0408152 **	$	3,380	
29	Property Taxes - Account 0408000		6,087	
30	Total Test Period Taxes		9,467	
31				
32	**JAAR Depreciation and Amortization Expense**			
33	Cost of Service-Amortization of Acquisition Premium	$	12,759	[2]
34	Annualized Depreciation expense amount NC-0800		32,092	[1]
35	Incremental amount for new depreciation rates in NC-1000		1,162	[1]
36	SubTotal Depreciation and Amortization Expense		46,013	
37	Nuclear decommissioning expenses - Account 0403800		4,467	[1]
38	Total Depreciation and Amortization Expense to remove		50,480	

[1] Compiled from JAAR filings
[2] E-1 Item 2, Trial Balance
* These amounts represent revenue that would have been billed to PA under the OFA agreement. No revenue was actually billed during the test period.
** These amounts represent expense reimbursal that would have been billed to PA under the OFA agreement. No expenses were billed during the test period.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize Depreciation on year end plant balances
For the test period ended December 31, 2018

NC-0800
Supplemental
January Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma annualizes depreciation expense, income taxes, amortization of investment tax credit and accumulated depreciation to reflect a full year's level of depreciation on plant in service as of the end of the test period.

The impact to depreciation expense is determined by multiplying current depreciation rates times the level of plant in service as of the end of the test period and then subtracting actual depreciation expense booked during the test period.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

The impact to amortization of investment tax credit reflects the difference between actual amortization booked during the test period and the new annual level of amortization based on the new depreciation study.

The impact to accumulated depreciation reflects one year's worth of the depreciation expense adjustment.

January Update

Revised NC-0804 for change in treatment of Catalyst Depreciation

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize Depreciation on year end plant balances
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0800
Supplemental
January Update

Line No.	Description	Source	Total NC Retail January	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.		-	-	-
11	Depreciation and amortization	NC-0801	41,407	42,068	(661)
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-0801	(9,594)	(9,747)	153
15	Amortization of investment tax credit	NC-0801	(1,481)	(1,481)	-
16					
17	Total electric operating expenses	Sum L6 through L15	30,333	30,841	(508)
18					
19	Operating income	L4 - L17	$ (30,333)	$ (30,841)	$ 508
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35	Plant held for future use		-	-	-
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40	Customer deposits		-	-	-
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize Depreciation on year end plant balances
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0801
Supplemental
January Update

Line No.	Description	Total System	NC Retail Allocation	Total NC Retail
1	Depreciation and amortization			
2	Production (NC-0802 Col E; Lines 7, 13,19, 27) - L3 - L4	$ 63,804	61.5278% [1]	$ 39,257
3	Production Direct assigned to NC (NC-0802 Col E; Lines 4, 6, 26)	158	100.0000%	158
4	Production Direct assigned to SC (NC-0802 Col E; Lines 5, 12, 18, 25)	11,672	0.0000%	-
5	Transmission (NC-0802 Col E; Line 35) - L6 - L7 - L8	2,758	59.6699% [2]	1,646
6	Transmission Direct assigned to NC (NC-0802 Col E; Line 32)	(86)	100.0000%	(86)
7	Transmission Direct assigned to SC (NC-0802 Col E; Line 33)	507	0.0000%	-
8	Transmission Direct assigned to Wholesale (NC-0802 Col E; Line 34)	(7)	0.0000%	-
9	Distribution (NC-0802 Col E; Line 43) - L10 - L11 - L12	(2,752)	87.1486% [3]	(2,398)
10	Distribution Direct assigned to NC (NC-0802 Col E; Line 40)	(1,043)	100.0000%	(1,043)
11	Distribution Direct assigned to SC (NC-0802 Col E; Line 41)	(5,827)	0.0000%	-
12	Distribution Direct assigned to Wholesale (NC-0802 Col E; Line 42)	(0)	0.0000%	-
13	General (NC-0802 Col E; Line 59) - L14 - L15	5,232	74.0412% [4]	3,874
14	General Direct assigned to SC (NC-0802 Col E; Line 58)	869	0.0000%	-
15	General Direct assigned to Wholesale (NC-0802 Col E; Line 56)	(1)	0.0000%	-
16	Intangible (NC-0802 Col E; Line 65)	(0)	67.9178% [5]	(0)
17	Adjust to depreciation and amortization (Sum L2 through L16)	$ 75,284		$ 41,407
18				
19	Adjust to deprec. and amort. for costs recovered in riders	$ - [8]	61.5278% [1]	$ - [8]
20				
21	Impact to depreciation and amortization (L17 + L19)	$ 75,284		$ 41,407
22				
23	Statutory tax rate	23.1693% [6]		23.1693% [6]
24				
25	Impact to income taxes (-L21 x L23)	$ (17,443)		$ (9,594)
26				
27	Amortization of investment tax credit			
28	Investment tax credit 2018	$ (3,356) [7]		
29	Estimated annual investment tax credit	(5,583) [7]		
30	Impact to amortization of investment tax credit - variance (-L28 + L29)	$ (2,227)		$ (1,481) [7]
31				
32	Impact to operating income (-L21 - L25 - L30)	$ (55,614)		$ (30,333)

[1] NC Retail Allocation Factor - DPALL
[2] NC Retail Allocation Factor - DTALL
[3] NC Retail Allocation Factor - RB PLT O DI
[4] NC Retail Allocation Factor - RB PLT O GN
[5] NC Retail Allocation Factor - PTDG
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] NC-0803 - Amortization of investment tax credit
[8] In the supplemental January update, DEP is proposing to no longer flow cataylst depreciation expense through the fuel rider, therefore the adjustment from NC-0804 is no longer needed.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize Depreciation on year end plant balances
For the test period ended December 31, 2018

NC-0802
Supplemental
January Update

Adjustment of Depreciation Expense to Reflect Plant in Service for 12 Months Ended December 31, 2018

Line No.	Function	(A) Gross Plant in Service 12/31/2018	(B) Depr Rate	(C) Current Rates Calculated Accrual	(D) Actual 12ME Depr Booked	(E) Difference
1	STEAM: [1]					
2	STEAM PLANT (excluding Clean Air Facilities 312.10)	$ 4,009,158,561	3.75%	$ 150,343,446	$ 136,632,876	$ 13,710,570
3	LAND RIGHTS - STEAM	32,975,133	0.30%	98,925	83,894	15,032
4	NC DEFERRALS - STEAM	-	3.75%	-	(164,036)	164,036
5	SC DEFERRALS - STEAM	-	3.75%	-	(3,218,645)	3,218,645
6	NC IMPAIRMENT - STEAM	(10,393,000)	3.75%	(389,738)	(391,224)	1,487
7		$ 4,031,740,694		$ 150,052,634	$ 132,942,865	$ 17,109,769
8						
9	NUCLEAR: [1]					
10	NUCLEAR PLANT	$ 9,764,139,291	2.80%	$ 273,395,900	$ 240,099,799	$ 33,296,101
11	LAND RIGHTS - NUCLEAR	74,482,903	1.20%	893,795	670,849	222,946
12	SC DEFERRALS - NUCLEAR	-	2.80%	-	(3,784,167)	3,784,167
13		$ 9,838,622,194		$ 274,289,695	$ 236,986,481	$ 37,303,214
14						
15	HYDRO: [1]					
16	HYDRAULIC PLANT	$ 141,110,321	3.47%	$ 4,896,528	$ 4,619,553	$ 276,975
17	LAND RIGHTS - HYDRO	2,828,917	2.52%	71,289	3,737	67,551
18	SC DEFERRALS - HYDRO	-	3.47%	-	(64,917)	64,917
19		$ 143,939,238		$ 4,967,817	$ 4,558,374	$ 409,443
20						
21	OTHER PRODUCTION: [1]					
22	OTHER (CT's)	$ 2,935,214,770	4.46%	$ 130,984,982	$ 115,791,041	$ 15,193,941
23	OTHER (CT's Land)	10,002,051	2.65%	265,054	126,537	138,517
24	OTHER (SOLAR)	192,220,870	5.15%	9,903,296	9,021,078	882,218
25	SC DEFERRALS - OTHER	-	4.46%	-	(4,604,333)	4,604,333
26	NC IMPAIRMENT - OTHER	(639,277)	4.46%	(28,528)	(20,929)	(7,599)
27		$ 3,136,798,414		$ 141,124,804	$ 120,313,393	$ 20,811,412
28						
29	TRANSMISSION: [1]					
30	TRANSMISSION OTHER	$ 2,558,664,776	1.90%	$ 48,614,631	$ 46,007,161	$ 2,607,470
31	TRANSMISSION RIGHT OF WAY	195,626,597	1.15%	2,249,706	2,099,248	150,458
32	NC DEFERRALS - TRANSMISSION	-	1.90%	-	86,091	(86,091)
33	SC DEFERRALS - TRANSMISSION	-	1.90%	-	(506,930)	506,930
34	OATT CONTRA	(4,948,324)	1.90%	(94,018)	(87,113)	(6,905)
35		$ 2,749,343,049		$ 50,770,318	$ 47,598,456	$ 3,171,862
36						
37	DISTRIBUTION: [1]					
38	DISTRIBUTION OTHER	$ 6,869,446,272	2.50%	$ 171,736,157	$ 175,022,852	$ (3,286,695)
39	DISTRIBUTION RIGHT OF WAY	75,442,609	1.28%	965,665	430,943	534,722
40	NC DEFERRALS - DISTRIBUTION	-	2.50%	-	1,043,015	(1,043,015)
41	SC DEFERRALS - DISTRIBUTION	-	2.50%	-	5,826,956	(5,826,956)
42	OATT CONTRA	(121,924)	2.50%	(3,048)	(2,700)	(348)
43		$ 6,944,766,956		$ 172,698,774	$ 182,321,067	$ (9,622,293)
44						
45	GENERAL: [1]					
46	LAND AND LAND RIGHTS	$ 8,184,032	0.00%	$ -	$ 28,317	$ (28,317)
47	STRUCTURES AND IMPROVEMENTS	155,760,504	2.42%	3,769,404	3,816,712	(47,308)
48	FURNITURE AND EQPMT	25,103,166	5.00%	1,255,158	1,346,267	(91,109)
49	EDP EQUIPMENT	61,610,744	12.50%	7,701,343	4,523,356	3,177,987
50	TRANSPORTATION EQUIPMENT [2]	69,975,818	10.29%	-	-	-
51	STORES EQUIPMENT	2,059,933	5.00%	102,997	125,933	(22,936)
52	TOOLS, SHOPS & GARAGE EQPMT	90,247,659	5.00%	4,512,383	3,688,128	824,255
53	LABORATORY EQUIPMENT	6,739,789	6.67%	449,544	485,500	(35,956)
54	POWER OPERATED EQUIPMENT	5,813,191	5.99%	348,210	492,453	(144,243)
55	COMMUNICATION EQUIPMENT	180,187,586	5.00%	9,009,379	7,428,901	1,580,478
56	OATT CONTRA - COMM EQUIP	(133,505)	5.00%	(6,675)	(5,882)	(794)
57	MISCELLANEOUS EQUIPMENT	23,064,322	5.00%	1,153,216	1,133,737	19,479
58	SC DEFERRALS - GENERAL	-		-	(869,299)	869,299
59		$ 628,613,238		$ 28,294,959	$ 22,194,124	$ 6,100,835
60						
61	INTANGIBLE [3]					
62	ORGANIZATION	$ 717,237	0.00%	$ -	$ -	$ -
63	FRANCHISES AND CONSENTS	59,871,453	various	2,644,321	2,644,321	(0)
64	MISC INTANGIBLE PLT	466,781,700	various	39,445,452	39,445,452	(0)
65		$ 527,370,391		$ 42,089,773	$ 42,089,773	$ (0)
66						
67	TOTAL PLANT-IN-SERVICE	$ 28,001,194,174		$ 864,288,775	$ 789,004,532	$ 75,284,243

[1]: The amounts above are shown at Gross Plant in Service Costs. Contra AFUDC has been added back to PowerPlant dollars through the on top in account 101000 at C and the Contra AFUDC depreciation expense that is calculated in 403002 is offset by including Contra AFUDC Offset depreciation groups at E.
[2]: Depreciation expense on Vehicles and Construction Equipment are recorded to 803 accounts, rather than 403/404 accounts. Therefore the depreciation expense associated with these assets is excluded from the schedule above.
[3]: Totals may not foot due to rounding
Note 4: Some assets within Misc Intangible Plt are fully amortized and no longer accrue any expense
Note 5: Land, Land Rights and Rights of Way noted separately from the rest of Electric Plant in Service above. Land is not a depreciable asset while Land Rights and R/W are depreciable.
Note 6: The calculated accrual column above assumes 12 months of depreciation. If any assets were added during the 12 month period, depreciation would be calculated based on the in-service date in the actual 12me depr booked column above.

Source: Duke Energy Progress - Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize Depreciation on year end plant balances
For the test period ended December 31, 2018

NC-0803
Supplemental
January Update

Amortization of investment tax credit [1]

Line No.	Description	A Test Year [2]	B Adjusted	B - A Adjustment	NC Retail Allocation	Total NC Retail
1	Production-Gross	$ (2,572,627)	$ (4,083,874)	$ (1,511,247)	61.5278% [3]	$ (929,837)
2	Transmission	(275,392)	(531,270)	(255,878)	59.6699% [4]	(152,682)
3	Distribution	(413,806)	(852,207)	(438,401)	87.1486% [5]	(382,060)
4	General	(93,835)	(115,397)	(21,562)	74.0412% [6]	(15,965)
5	Total [L1 through L4]	$ (3,355,660)	$ (5,582,749)	$ (2,227,089)		$ (1,480,545)

[1] Information provided by Duke Energy Tax Department
[2] E-1 Item 2 - Working Trial Balance - Account 0411410
[3] NC Retail Allocation Factor - DPALL
[4] NC Retail Allocation Factor - DTALL
[5] NC Retail Allocation Factor - RB PLT O DI
[6] NC Retail Allocation Factor - RB PLT O GN

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize depreciation on year end plant balances
For the test period ended December 31, 2018

NC-0804
Supplemental
January Update

Adjustment to Annualize Depreciation Expense at December 31, 2018 - Costs recovered through riders

Line No.	Function	Plant in Service 12/31/2018 [1]	Depr Rate [1]	Current Rates Calculated Accrual	Actual 12ME Depr Booked [1]	Difference	Adjustment	
1	Steam 312 - SCR Catalyst	$ 40,770,378	4.08%	$ 1,663,431	$ 2,737,650	$ (1,074,218)	$ -	[2]
2								
3		$ 40,770,378		$ 1,663,431	$ 2,737,650	$ (1,074,218)	$ -	

[1] NC-2602 - Comprarison of Current And Proposed Depreciation Parameters, Rates and Accruals
[2] In the supplemental January update, DEP is proposing to no longer flow cataylst depreciation expense through the fuel rider, therefore this adjustment is no longer needed.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018

NC-1000
Supplemental
February Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts depreciation expense, general taxes, income taxes, electric plant in service, accumulated depreciation, working capital investment, accumulated deferred income taxes and construction work in progress to reflect net additions to plant in service.

The impact to operating income is determined as follows:
The adjustment to depreciation expense reflects a full year's level of depreciation on net additions to plant in service by multiplying the projected additions to net electric plant by depreciation rates based on the new depreciation study.

The adjustment to general taxes reflects estimated annual property tax expense related to the net additions to plant in service. Property taxes are estimated by multiplying the projected net additions to electric plant by a combined North Carolina and South Carolina property tax rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

The impact to rate base is determined as follows:
The adjustment to electric plant in service reflects projected updates to electric plant in service through February 2020.

The adjustment to accumulated depreciation reflects projected updates to the accumulated depreciation balance through February 2020 and annualized depreciation expense based on forecasted February 2020 electric plant in service balances.
The adjustment to working capital investments reflects projected updates to the unrecovered net book value of retired meters regulatory asset through February 2020.
The adjustment to accumulated deferred income taxes reflects the impacts of projected bonus depreciation on gross plant additions through February 2020.
The adjustment to construction work in progress is to remove the balance related to Asheville CC that was included in rate base in the last rate case. Asheville CC is forecasted to go in service during the capital cutoff period.

October Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through October 2019.
Corrected references to Duke Energy Carolinas in footnotes

November Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through November 2019. Updated forecasted DSDR numbers on NC-1007, NC-1008, and NC-1009 based on revised DSDR asset balances.

December Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through December 2019.

January Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through January 2020.

February Update
Updated NC-1005, NC-1007, NC-1008, NC-1009 and NC-1010 for actuals through February 2020. NC-1008 been updated to include Asheville CC Unit 8, which expected in service in March 2020.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1000
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization	NC-1001	61,840	70,469	(8,630)
12	General taxes	NC-1001	4,963	6,600	(1,637)
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1001	(15,478)	(17,857)	2,379
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	51,325	59,213	(7,888)
18					
19	Operating income	L4 - L17	$ (51,325)	$ (59,213)	$ 7,888
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-1001	$ 1,444,396	$ 1,845,936	$ (401,540)
29	Accumulated depreciation and amortization	NC-1001	(127,842)	(383,473)	255,631
30	Electric plant in service, net	Sum L28 through L29	$ 1,316,554	$ 1,462,463	$ (145,910)
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment	NC-1001	18,763	(1,458)	20,220
35					
36					
37	Less:				
38	Accumulated deferred taxes	NC-1001	(56,542)	(31,249)	(25,293)
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress	NC-1001	(102,930)	(102,930)	-
43					
44	Total impact to rate base	Sum L30 through L42	$ 1,175,844	$ 1,326,826	$ (150,982)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1001
Supplemental
February Update

Line No.	Description	Electric Plant	Depr Rate	Depr.	Total System	NC Retail Allocation	Total NC Retail
1	Impact to Rate Base Line Items						
2	Total net additions to electric plant:						
3	Fossil	$ (196,649) [1]	5.33% [2]	$ (10,481)			
4	Nuclear	333,720 [1]	3.31% [2]	11,046			
5	Hydro	13,247 [1]	3.70% [2]	490			
6	Other Production	830,777 [1]	5.08% [2]	42,203			
7	Transmission	264,107 [1]	2.23% [2]	5,890			
8	Distribution	692,509 [1]	2.39% [18]	16,551			
9	Distribution - AMR Meter Retirements	(61,039) [17]					
10	General	77,411 [1]	5.74% [2]	4,443			
11	Intangible	105,665 [1]	[13]	20,607			
12	Total net additions to depreciable electric plant (L3 through L11)	$ 2,059,748		$ 90,749			
13							
14	Summary of impacts to rate base						
15	Net additions to total electric plant in service:						
16	Production Plant				$ 982,219 [1]	61.5278% [4]	$ 604,338
17	Production Direct Assignments - NC				3,069 [1]	100.0000%	3,069
18	Direct Assignments - SC				352 [1]	0.0000%	-
19	Direct Assignments - WHS				(4,543) [1]	0.0000%	-
20	Transmission plant				264,105 [1]	59.6699% [5]	157,591
21	Distribution plant				631,470 [1]	87.1486% [6]	550,317
22	General plant				77,411 [1]	74.0412% [7]	57,316
23	Intangible plant				105,665 [1]	67.9178% [8]	71,765
24	Impact to electric plant in service (Sum L16 through L23)				$ 2,059,748		$ 1,444,396
25							
26	Accumulated depreciation & amortization:						
27	Production Plant				$ (78,079) [3]	61.5278% [4]	$ (48,040)
28	Production Direct Assignments - NC				27,632 [3]	100.0000%	27,632
29	Direct Assignments - SC				2,714 [3]	0.0000%	-
30	Direct Assignments - WHS				1,625 [3]	0.0000%	-
31	Transmission				(32,884) [3]	59.6699% [5]	(19,622)
32	Distribution				(8,550) [3]	87.1486% [6]	(7,451)
33	General				(19,522) [3]	74.0412% [7]	(14,455)
34	Intangible				(65,987) [3]	67.9178% [8]	(44,817)
35	Adjustment to accumulated depreciation & amortization (Sum L27 through L34)				$ (173,051)		$ (106,753)
36	Additional adjustment for Feb. 29, 2020 annualization				$ (31,950) [14]		$ (21,089) [14]
37	Impact to accumulated depreciation and amortization (L35 + L36)				$ (205,002)		$ (127,842)
38							
39	Net electric plant:						
40	Production (L16 + L27)				$ 904,140		$ 556,297
41	Direct Assignments - NC (L17 + L28)				30,701		30,701
42	Direct Assignments - SC (L18 + L29)				3,066		-
43	Direct Assignments - WHS (L19 + L30)				(2,918)		-
44	Transmission (L20 + L31)				231,221		137,969
45	Distribution (L21 + L32)				622,920		542,866
46	General (L22 + L33)				57,889		42,862
47	Intangible (L23 + L34)				39,678		26,949
48	Adjustment to net plant (Sum L40 through L47)				$ 1,886,696		$ 1,337,643
49	Additional adjustment for Feb. 29, 2020 annualization				$ (31,950) [14]		$ (21,089) [14]
50	Total net plant (L48 + L49)				$ 1,854,746		$ 1,316,554
51							
52	Working capital investment:						
53	Net change in NC Unrecovered NBV of Retired Meters				$ 18,763 [15]		$ 18,763 [15]
54	Impact to working capital investment (L53)				$ 18,763		$ 18,763
55							
56	Accumulated deferred income tax:						
57	Resulting from additional bonus depreciation:						
58	Production				$ (73,552) [9]	61.5278% [4]	$ (45,255)
59	Transmission				(2,508) [9]	59.6699% [5]	(1,496)
60	Distribution				(1,474) [9]	87.1486% [6]	(1,285)
61	General				(356) [9]	74.0412% [7]	(264)
62	Intangible				(5,734) [9]	67.9178% [8]	(3,895)
63	Adjustment resulting from additional bonus depreciation (Sum L58 through L62)				$ (83,625)		$ (52,195)
64	Adjustment resulting from Meter working capital investment				$ (4,347) [15]		$ (4,347) [15]
65	Impact to accumulated deferred income tax (L63 + L64)				$ (87,972)		$ (56,542)
66							
67	Construction work in progress:						
68	Remove Asheville CWIP in rate base				$ (169,850) [16]		$ (102,930) [16]
69	Impact to construction work in progress				$ (169,850)		$ (102,930)
70							
71	Impact to rate base (L50 + L54 + L65 + L69)				$ 1,615,687		$ 1,175,844

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1001
Supplemental
February Update

Line No.	Description	Total System	NC Retail Allocation	Total NC Retail
72	Impact to Income Statement Line Items			
73	Depreciation and amortization:			
74	Production (Sum L3 through L6)	$ 43,258	61.5278% [4]	$ 26,616
75	Transmission (L7)	5,890	59.6699% [5]	3,514
76	Distribution (L8)	16,551	87.1486% [6]	14,424
77	General (L10)	4,443	74.0412% [7]	3,290
78	Intangible (L11)	20,607	67.9178% [8]	13,996
79	Impact to depreciation and amortization (Sum L74 through L78)	$ 90,749		$ 61,840
80				
81	General taxes:			
82	Average property tax rate - North Carolina	0.22148% [10]		
83	Average property tax rate - South Carolina	0.14111% [10]		
84	Average property tax rate-Combined NC and SC (L82 + L83)	0.36259%		
85				
86	Production - Excluding Solar (((Sum L3 through Sum L6) - NC-1008 Line 39) x L84)	$ 3,558	61.5278% [4]	$ 2,189
87	Production - Solar	(0) [12]	61.5278% [4]	(0)
88	Transmission (L7 x L84)	958	59.6699% [5]	571
89	Distribution (L8 + L9 x L84)	2,290	87.1486% [6]	1,995
90	General (L10 x L84)	281	74.0412% [7]	208
91	Impact to general taxes (Sum L86 through L90)	$ 7,085		$ 4,963
92				
93	Taxable income (-L79 - L91)	$ (97,835)		$ (66,803)
94	Statutory tax rate	23.1693% [11]		23.1693% [11]
95	Impact to income taxes (L93 x L94)	$ (22,668)		$ (15,478)
96				
97	Impact to operating income (L93 - L95)	$ (75,167)		$ (51,325)

[1] NC-1002 - Net Plant Adds
[2] NC-2602 - Comparison of Current and Proposed Depreciation as of December 31, 2018, Proposed Rate Column
[3] NC-1003 - Accumulated Depreciation
[4] Allocation Factor - DPALL
[5] Allocation Factor - DTALL
[6] Allocation Factor - RB PLT O DI
[7] Allocation Factor - RB PLT O GN
[8] Allocation Factor - PTDG
[9] NC-1004 - Accumulated Deferred Income Taxes Calculation
[10] NC-0901 - Annualize property taxes on year end plant balances, Line 16
[11] NC-0104 - 2019 Calculation of Tax Rates - Composite Tax Rate, Line 10
[12] NC-1008 - Plant in Service Balances - Solar additions are included at 20% of total based on property tax exclusion for solar assets per Tax Department.
[13] Updated annualized depreciation on intangible additions per Asset Accounting.
[14] NC-1006 - Accumulated Depreciation Annualization Adjustment
[15] NC-1005 - NC Unrecovered Net Book Value of Retired Meters, Line 24 and Line 28
[16] NC-1011 - Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142
[17] AMR meter retirements, from Asset Accounting, should not have an impact on depreciation expense, recovering retired AMR meters in reg asset.
[18] Distribution composite rate without AMR meter line from the proposed 2018 Depreciation Study

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1002
Supplemental
February Update

Net Plant Adds

Line No.	Item	Total System: Actual [1] Net Change through 2/29/2020	Total System: Adjustments		Total System: Total Adjusted Net Change Plant in Service
1	Electric Plant in Service:				
2	Steam plant	$ (173,888)	$ (22,762)	[2]	$ (196,649)
3	Nuclear plant	409,201	(75,480)	[2]	333,720
4	Hydro plant	13,247			13,247
5	Other production plant	830,777			830,777
6	Transmission plant	264,107	-	[3]	264,107
7	Distribution plant	662,390	(30,921)	[3]	631,470
8	General plant	84,110	(6,699)	[3]	77,411
9	Intangible plant	105,665	-	[3]	105,665
10	Total Electric Plant in Service (Sum L2 through L9)	$ 2,195,610	$ (135,862)		$ 2,059,748
11					
12	COS Eletric Plant in Service				
13	Production Plant	$ 1,080,461	$ (98,242)	[2]	$ 982,219
14	Direct Assignments - NC	3,069			3,069
15	Direct Assignments - SC	352			352
16	Direct Assignments - WHS	(4,543)			(4,543)
17	Transmission plant	264,105	-	[3]	264,105
18	Distribution plant	662,390	(30,921)	[3]	631,470
19	General plant	84,110	(6,699)	[3]	77,411
20	Intangible plant	105,665	-	[3]	105,665
21	Total COS Electric Plant in Service (Sum L13 through L20)	$ 2,195,610	$ (135,862)		$ 2,059,748
22					
23	Electric Plant in Service recovered in riders included above:				
24	JAAR - Steam plant	$ 22,762	$ 22,762	[2]	
25	JAAR - Nuclear plant	75,480	75,480	[2]	
26	JAAR - Acquisition Adjustment	0	0	[2]	
27	DSDR - Transmission	-	-	[3]	
28	DSDR - Distribution	30,921	30,921	[3]	
29	DSDR - General plant	6,699	6,699	[3]	
30	DSDR - Intangibles	-	-	[3]	
31	Total EPIS recovered in riders (Sum L24 through L29)	$ 135,862	$ 135,862		

[1] NC-1008 - Plant in Service Balances
[2] Amounts related to balances that are collected through the JAAR and should be excluded for purposes of this analysis.
[3] Amounts related to balances that are collected through the DSDR rider and should be excluded for purposes of this analysis.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1003
Supplemental
February Update

Accumulated Depreciation

Line No.	Item	Total System: Actual [1] Net Change through 2/29/2020	Adjustments		Total Adjusted Net Change Accumulated Depreciation
1	COS Accumulated Depreciation:				
2	Production Plant	$ (133,156)	55,077	[2]	$ (78,079)
3	Direct Assignments - NC	27,632			27,632
4	Direct Assignments - SC	2,714			2,714
5	Direct Assignments - WHS	1,625			1,625
6	Transmission plant	(32,898)	13	[3]	(32,884)
7	Distribution plant	(14,758)	6,208	[3]	(8,550)
8	General plant	(20,814)	1,292	[3]	(19,522)
9	Intangible plant	(66,374)	387	[3]	(65,987)
10	Total COS Accumulated Depreciation (Sum L2 through L9)	$ (236,029)	$ 62,977		$ (173,051)
11					
12	Accumulated Depreciation recovered in riders included above:				
13	JAAR - Steam plant	$ (6,349)	$ (6,349)	[2]	
14	JAAR - Nuclear plant	(33,843)	(33,843)	[2]	
15	JAAR - Acquisition Adjustment	(14,885)	(14,885)	[2]	
16	DSDR - Transmission	(13)	(13)	[3]	
17	DSDR - Distribution	(6,208)	(6,208)	[3]	
18	DSDR - General plant	(1,292)	(1,292)	[3]	
19	DSDR - Intangibles	(387)	(387)	[3]	
20	Total Accum Depr recovered in riders (Sum L13 through L19)	$ (62,977)	$ (62,977)		

[1] NC-1009 - Accumulated Depreciation Balances
[2] Amounts related to balances that are collected through the JAAR and should be excluded for purposes of this analysis.
[3] Amounts related to balances that are collected through the DSDR rider and should be excluded for purposes of this analysis.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1004
Supplemental
February Update

Accumulated Deferred Income Taxes Calculation

Line No.	Item		Total System Forecasted Bonus Depreciation through 2/29/2020	
1	Bonus Depreciation			
2	Steam plant	$	69,762	[1]
3	Nuclear plant		59,790	[1]
4	Hydro plant		292	[1]
5	Other production plant		187,609	[1]
6	Transmission plant		10,824	[1]
7	Distribution plant		6,363	[1]
8	General plant		1,538	[1]
9	Intangible plant		24,750	[1]
10	Total Accumulated Depreciation (Sum L2 through L9)	$	360,929	
11				
12	Statutory tax rate		23.1693%	[2]
13				
14	Accumulated deferred income taxes (resulting from additional bonus depreciation):			
15	Steam plant (-L2 x L12)	$	(16,163)	
16	Nuclear plant (-L3 x L12)		(13,853)	
17	Hydro plant (-L4 x L12)		(68)	
18	Other production plant (-L5 x L12)		(43,468)	
19	Transmission plant (-L6 x L12)		(2,508)	
20	Distribution plant (-L7 x L12)		(1,474)	
21	General plant (-L8 x L12)		(356)	
22	Intangible plant (-L9 x L12)		(5,734)	
23	Impact to accumulated deferred income taxes (Sum L15 through L22)	$	(83,625)	

[1] Forecasted amounts provided by Duke Energy Progress - Tax Department
[2] NC-0104 - 2019 Calculation of Tax Rates - Composite Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018

NC-1005
Supplemental
February Update

NC Unrecovered Net Book Value of Retired Meters

Line No.	Description	Total NC Retail	
1	NC Unrecovered NBV of Retired Meter Reg Asset Balance:		
2	Dec 2018	$ 11,503,875	[1]
3	Jan 2019	11,503,875	[1]
4	Feb 2019	11,503,875	[1]
5	Mar 2019	17,441,466	[1]
6	Apr 2019	17,441,466	[1]
7	May 2019	17,441,466	[1]
8	Jun 2019	21,619,389	[1]
9	Jul 2019	21,619,389	[1]
10	Aug 2019	21,619,389	[1]
11	Sep 2019	23,513,015	[1]
12	Oct 2019	23,513,015	[1]
13	Nov 2019	23,513,015	[1]
14	Dec 2019	27,790,778	[1]
15	Jan 2020	27,790,778	[1]
16	Feb 2020	30,266,524	[1]
17			
18	Amortization period per 2016 Depreciation Study - Months (10 yrs x 12)	120	[2]
19			
20	Date new depreciation rates effective	3/16/2018	
21	Number of periods left to amortize at 12/31/2018 (L18 - 9.5)	110.5	
22			
23	Monthly amortization based on regulatory asset balance at 12/31/2018 ((L2 / L21)	$ 104,107	
24			
25	Forecasted net change through 02/29/2020 (L15 - L2)	18,762,650	
26			
27	Statutory tax rate	23.1693%	[3]
28			
29	Impact to accumulated deferred income taxes (-L25 x L27)	$ (4,347,175)	

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Remaining life of Meters to be replaced during the AMI deployment settled in the 2016 Depreciation Study
[3] NC-0104 - 2019 Calculation of Tax Rates - Composite Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1006
Supplemental
February Update

Accumulated Depreciation Annualization Adjustment

Line No.	Item	Total System	Adjustments	Total Adjusted System	NC Retail Allocation	Total NC Retail
1	Accumulated Depreciation					
2	Production (Line 5 + Line 9 + Line 13 + Line 19) - L3	$ (27,235) [1]	$ 604 [2]	$ (26,631)	61.5278% [4]	$ (16,386)
3	Production Direct assigned to NC (Line 4 + Line 18)	(18) [1]		(18)	100.0000%	(18)
4	Production Direct assigned to WHS (Line 4 + Line 18)	187 [1]		187	0.0000%	-
4	Transmission (Line 25) - L5	(3,019) [1]	-	(3,019)	59.6699% [5]	(1,801)
5	Transmission Direct assigned to Wholesale (Line 24)	5 [1]		5	0.0000%	-
6	Distribution (Line 31) - L7	(8,178) [1]	54	(8,124)	87.1486% [6]	(7,080)
7	Distribution Direct assigned to Wholesale (Line 30)	0 [1]		0	0.0000%	-
8	General (Line 46) - L9	5,743 [1]	$ 125	5,868	74.0412% [7]	4,345
9	General Direct assigned to Wholesale (Line 44)	(0) [1]		(0)	0.0000%	-
10	Intangible (Line 48)	- [1]	$ (218)	(218)	67.9178% [8]	(148)
11	Impact to accum. deprec. (Sum L2 through L10)	$ (32,514)	$ 564	$ (31,950)		$ (21,089)
12						
13	Accumulated Depreciation recovered in riders included above:					
14	JAAR - Steam plant	$ 16 [1]	$ 16 [2]			
15	JAAR - Nuclear plant	(620) [1]	(620) [2]			
16	DSDR - Transmission	- [1]	- [3]			
17	DSDR - Distribution	(54) [1]	(54) [3]			
18	DSDR - General plant	(125) [1]	(125) [3]			
19	DSDR - Intangibles	218 [1]	218 [3]			
20	Total Accum Depr recovered in riders (Sum L14 through L18)	$ (564)	$ (564)			

[1] NC-1007 - Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense at February 29, 2020
[2] Amounts related to balances forecasted to flow through the JAAR and should be excluded for purposes of this analysis.
[3] Amounts related to balances forecasted to flow through the DSDR rider and should be excluded for purposes of this analysis.
[4] Allocation Factor - DPALL
[5] Allocation Factor - DTALL
[6] Allocation Factor - RB PLT O DI
[7] Allocation Factor - RB PLT O GN
[8] Allocation Factor - PTDG

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1007
Supplemental
February Update

Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense at Feb. 29, 2020

Line No.	Function		Plant in Service [8] 2/29/2020	Depr Rate [9]		Current Rates Calculated Accrual		12ME Depr Booked [10]		Difference
1	STEAM: [1]									
2	STEAM PLANT	$	3,848,841	3.75%	$	144,332	$	154,170	$	(9,838)
3	LAND RIGHTS - STEAM		23,885	0.30%		72		30		41
4	NC IMPAIRMENT - STEAM		(10,393)	3.75%		(390)		(415)		25
5	WHS IMPAIRMENT - STEAM		(4,666)	3.75%		(175)		-		(175)
6		$	3,857,667		$	143,838	$	153,786	$	(9,947)
7	NUCLEAR: [1]									
8	NUCLEAR PLANT	$	10,169,379	2.80%	$	284,743	$	267,743	$	17,000
9	LAND RIGHTS - NUCLEAR		74,790	1.20%		897		677		221
10		$	10,244,169		$	285,640	$	268,420	$	17,220
11	HYDRO: [1]									
12	HYDRAULIC PLANT	$	154,358	3.47%	$	5,356	$	5,066	$	290
13	LAND RIGHTS - HYDRO		2,829	2.52%		71		4		68
14		$	157,186		$	5,427	$	5,069	$	358
15	OTHER PRODUCTION: [1]									
16	OTHER (CT's)	$	3,589,249	4.46%	$	160,171	$	140,862	$	19,310
17	OTHER (CT's Land)		10,002	2.65%		265		127		138
18	OTHER (SOLAR)		192,184	5.15%		9,901		9,895		6
19	NC IMPAIRMENT - OTHER		(639)	4.46%		(29)		(22)		(6)
20	WHS IMPAIRMENT - OTHER		(300)	4.46%		(13)		(1)		(12)
21		$	3,790,496		$	170,296	$	150,861	$	19,435
22										
23	TRANSMISSION: [1]									
24	TRANSMISSION OTHER	$	2,814,681	1.90%	$	53,479	$	50,540	$	2,938
25	TRANSMISSION RIGHT OF WAY		191,352	1.15%		2,201		2,120		80
26	OATT CONTRA - TRANS		(4,946)	1.90%		(94)		(89)		(5)
27		$	3,001,087		$	55,586	$	52,572	$	3,014
28										
29	DISTRIBUTION: [1]									
30	DISTRIBUTION OTHER	$	7,541,075	2.50%	$	188,527	$	180,935	$	7,592
31	DISTRIBUTION RIGHT OF WAY		78,566	1.28%		1,006		419		586
32	OATT CONTRA - DISTR		(122)	2.50%		(3)		(3)		(0)
33		$	7,619,518		$	189,529	$	181,352	$	8,178
34										
35	GENERAL: [1]									
36	LAND AND LAND RIGHTS	$	7,866	0.00%	$	-	$	27	$	(27)
37	STRUCTURES AND IMPROVEMENTS		171,677	2.42%		4,155		3,684		471
38	FURNITURE AND EQPMT		25,917	5.00%		1,296		781		515
39	EDP EQUIPMENT		77,981	12.50%		-		8,384		(8,384)
40	TRANSPORTATION EQUIPMENT [2]		63,213	10.29%		-		-		-
41	STORES EQUIPMENT		1,874	5.00%		94		98		(5)
42	TOOLS, SHOPS & GARAGE EQPMT		93,678	5.00%		4,684		4,573		110
43	LABORATORY EQUIPMENT		5,925	6.67%		395		422		(27)
44	POWER OPERATED EQUIPMENT		7,447	5.99%		446		375		71
45	COMMUNICATION EQUIPMENT		236,426	5.00%		11,821		10,026		1,795
46	OATT CONTRA - COMM EQUIP		(134)	5.00%		(7)		(7)		0
47	MISCELLANEOUS EQUIPMENT		20,854	5.00%		1,043		1,306		(263)
48		$	712,725		$	23,927	$	29,670	$	(5,743)
49										
50	INTANGIBLE [4]	$	633,035		$	55,553	$	55,553	$	-
51										
52	TOTAL PLANT-IN-SERVICE	$	30,015,884		$	929,797	$	897,282	$	32,514
53										
54	Electric Plant in Service recovered in riders included above:									
55	JAAR - Steam plant [11]	$	141,779		$	5,435	$	5,451	$	(16)
56	JAAR - Nuclear plant [11]		860,694			30,074		29,455		620
57	DSDR - Transmission [12]		607			12		12		-
58	DSDR - Distribution [12]		196,172			4,982		4,928		54
59	DSDR - General plant [12]		23,853			1,188		1,063		125
60	DSDR - Intangibles [12]		32,842			42		260		(218)
61	Total EPIS recovered in riders (Sum L55 through L60)	$	1,255,948		$	41,732	$	41,168	$	564

[1] The amounts above are shown at Gross Plant in Service Costs. Contra AFUDC has been added back to PowerPlant dollars through the on top in account 101000 at C and the Contra AFUDC depreciation expense that is calculated in 403002 is offset by including Contra AFUDC Offset depreciation groups at E.
[2] Depreciation expense on Vehicles and Construction Equipment are recorded to 803 accounts, rather than 403/404 accounts. Therefore the depreciation expense associated with these assets is excluded from the schedule above.
[3] Totals may not foot due to rounding
[4] Some assets within Misc Intangible Plt are fully amortized and no longer accrue any expense
[5] Land, Land Rights and Rights of Way noted separately from the rest of Electric Plant in Service above. Land is not a depreciable asset while Land Rights and R/W are depreciable.
[6] The calculated accrual column above assumes 12 months of depreciation. If any assets were added during the 12 month period, depreciation would be calculated based on the in-service date in the actual 12me depr booked column above.
[7] The per book intangible amount reflects a representative level of amortization expense on a go forward basis.
[8] Actual amounts provided by Duke Energy Progress - Asset Accounting
[9] NC-0802 - Adjustment to Annualize Depreciation Expense at December 31, 2018
[10] NC-1010 - Twelve Months of Depreciation Expense as of February 29, 2020
[11] Actual balances, calculated accrual and forecasted 12 months ended depreciation expense provided by Rates and Regulatory - Joint Agency

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1008
Supplemental
February Update

Plant in Service Balances

Line No.	Description	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Asheville CC [5][6]	Net Change
		ACTUALS [1][4]																
		a	b	c	d	e	f	g	h	i	j	k	l	m	n	o		p = o - a
1	Electric Plant in Service																	
2	Steam plant	$ 4,011,861	$ 4,043,991	$ 4,046,676	$ 4,101,612	$ 4,231,983	$ 4,266,772	$ 4,275,052	$ 4,292,783	$ 4,306,563	$ 4,313,743	$ 4,309,252	$ 4,312,479	$ 4,309,657	$ 3,848,827	$ 3,837,973	$ -	$ (173,888)
3	Nuclear plant	8,909,317	8,916,989	8,917,204	8,939,103	9,029,753	9,056,127	9,081,959	9,093,484	9,098,689	9,109,080	9,108,234	9,183,798	9,298,320	9,331,546	9,318,517	-	409,201
4	Hydro plant	143,939	143,757	145,271	145,487	146,482	146,454	146,485	146,479	151,468	152,038	152,192	152,140	153,412	153,538	157,186	-	13,247
5	Other production plant	3,136,771	3,088,719	3,118,877	3,138,170	3,138,093	3,142,793	3,147,464	3,149,023	3,155,174	3,157,109	3,158,903	3,175,483	3,667,888	3,773,704	3,790,495	177,054	830,777
6	Transmission plant	2,746,389	2,751,560	2,756,170	2,761,879	2,792,924	2,816,747	2,838,200	2,847,713	2,859,952	2,867,784	2,916,758	2,945,333	2,972,314	2,982,323	3,010,496	-	264,107
7	Distribution plant	6,944,764	6,980,196	7,025,165	7,065,340	7,113,068	7,180,132	7,239,028	7,289,075	7,343,981	7,385,517	7,441,019	7,483,903	7,497,343	7,543,797	7,607,154	-	662,390
8	General plant	628,616	633,557	639,855	637,103	639,433	646,714	647,285	653,753	650,568	651,968	658,169	660,967	679,878	706,522	712,727	-	84,110
9	Intangible plant	527,370	528,454	529,312	535,638	536,005	538,985	567,009	573,426	573,382	573,593	578,029	581,148	628,365	631,625	633,035	-	105,665
10	Total Electric Plant in Service (Sum L2 through L9)	$ 27,049,028	$ 27,087,223	$ 27,178,530	$ 27,324,333	$ 27,627,742	$ 27,794,724	$ 27,942,482	$ 28,045,736	$ 28,139,777	$ 28,210,833	$ 28,322,555	$ 28,495,252	$ 29,207,178	$ 28,971,882	$ 29,067,584	$ 177,054	$ 2,195,610
11																		
12	Direct Assignments in COS Included above																	
13	Contra AFUDC - WHS	$ (43,604)	$ (43,604)	$ (43,597)	$ (43,591)	$ (43,591)	$ (43,591)	$ (43,494)	$ (43,476)	$ (43,461)	$ (43,417)	$ (43,283)	$ (43,283)	$ (43,252)	$ (43,190)	$ (43,184)	$ -	$ 421
14	Contra AFUDC - NC Retail	(321,021)	(321,021)	(320,951)	(320,883)	(320,883)	(320,872)	(320,384)	(320,218)	(320,131)	(319,769)	(318,680)	(318,680)	(318,454)	(318,003)	(317,952)	-	3,069
15	Contra AFUDC - SC Retail	(36,217)	(36,217)	(36,212)	(36,206)	(36,206)	(36,206)	(36,150)	(36,133)	(36,128)	(36,085)	(35,955)	(35,955)	(35,927)	(35,872)	(35,865)	-	352
16	Harris Disallowance - NC	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	-	-
17	Harris Disallowance - SC	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	-	-
18	Harris Disallowance - WHS	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	-	-
19	Harris Disallowance - PA	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	-	-
20	Production Plant - Other NC	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	-	-
21	Production Plant - WHS	-	-	-	-	-	-	-	-	-	-	-	-	(4,966)	(4,966)	(4,966)	-	(4,966)
22	OATT - WHS	(5,204)	(5,204)	(5,200)	(5,200)	(5,196)	(5,196)	(5,196)	(5,200)	(5,200)	(5,200)	(5,200)	(5,201)	(5,201)	(5,201)	(5,201)	-	2
23	Total Direct Assignments in COS (Sum L13 through L22)	$ (968,376)	$ (968,376)	$ (968,289)	$ (968,209)	$ (968,205)	$ (968,195)	$ (967,553)	$ (967,358)	$ (967,250)	$ (966,801)	$ (965,448)	$ (965,449)	$ (970,129)	$ (969,563)	$ (969,498)	$ -	$ (1,122)
24																		
25	COS Adjustments																	
26	Acquisition Adjustment	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ -	$ -
27	Total COS Adjustments (Sum L26)	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ -	$ -
28																		
29	COS Electric Plant in Service																	
30	Production Plant ((Sum L2 through L5 + L27) - Sum L13 through L21)	$ 17,514,863	$ 17,506,431	$ 17,540,919	$ 17,637,184	$ 17,859,123	$ 17,924,947	$ 17,963,119	$ 17,993,729	$ 18,023,745	$ 18,043,373	$ 18,038,630	$ 18,133,950	$ 18,744,008	$ 18,421,778	$ 18,418,270	$ 177,054	$ 1,080,461
31	Direct Assignments - NC (L14 + L16 + L20)	(719,990)	(719,990)	(719,919)	(719,852)	(719,851)	(719,841)	(719,352)	(719,187)	(719,099)	(718,738)	(717,649)	(717,649)	(717,423)	(716,972)	(716,921)	-	3,069
32	Direct Assignments - SC (L15 + L17)	(88,774)	(88,774)	(88,768)	(88,763)	(88,763)	(88,763)	(88,706)	(88,690)	(88,685)	(88,642)	(88,512)	(88,512)	(88,483)	(88,429)	(88,422)	-	352
33	Direct Assignments - WHS (L13 + L18 + L19 + L21 + L22)	(159,612)	(159,612)	(159,601)	(159,595)	(159,591)	(159,591)	(159,494)	(159,481)	(159,466)	(159,422)	(159,287)	(159,288)	(164,223)	(164,162)	(164,155)	-	(4,543)
34	Transmission plant (L6 - L22)	2,751,593	2,756,763	2,761,370	2,767,079	2,798,120	2,821,943	2,843,396	2,852,913	2,865,152	2,872,984	2,921,958	2,950,534	2,977,515	2,987,524	3,015,698	-	264,105
35	Distribution plant (L7)	6,944,764	6,980,196	7,025,165	7,065,340	7,113,068	7,180,132	7,239,028	7,289,075	7,343,981	7,385,517	7,441,019	7,483,903	7,497,343	7,543,797	7,607,154	-	662,390
36	General plant (L8)	628,616	633,557	639,855	637,103	639,433	646,714	647,285	653,753	650,568	651,968	658,169	660,967	679,878	706,522	712,727	-	84,110
37	Intangible plant (L9)	527,370	528,454	529,312	535,638	536,005	538,985	567,009	573,426	573,382	573,593	578,029	581,148	628,365	631,625	633,035	-	105,665
38	Total COS Electric Plant in Service (Sum L30 through L37)	$ 27,398,830	$ 27,437,025	$ 27,528,332	$ 27,674,135	$ 27,977,544	$ 28,144,526	$ 28,292,284	$ 28,395,538	$ 28,489,579	$ 28,560,635	$ 28,672,357	$ 28,845,054	$ 29,556,980	$ 29,321,684	$ 29,417,386	$ 177,054	$ 2,195,610
39																		
40	Solar Electric Plant in Service Included in Line 5 above	$ 192,221	$ 192,221	$ 192,221	$ 191,936	$ 192,022	$ 192,031	$ 192,031	$ 192,039	$ 192,221	$ 192,039	$ 192,082	$ 192,088	$ 192,088	$ 192,088	$ 192,174	$ -	$ (47)
41																		
42	Electric Plant in Service recovered in riders included above																	
43	JAAR - Steam plant [2]	$ 119,018														$ 141,779	$ -	$ 22,762
44	JAAR - Nuclear plant [2]	785,214														860,694	-	75,480
45	JAAR - Acquisition Adjustment [2]	349,802														349,802	-	0
46	DSDR - Transmission [3]	607														607	-	-
47	DSDR - Distribution [3]	165,251														196,172	-	30,921
48	DSDR - General plant [3]	17,154														23,853	-	6,699
49	DSDR - Intangibles [3]	32,842														32,842	-	-
50	Total EPIS recovered in riders (Sum L43 through L49)	$ 1,469,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,605,751	$ -	$ 135,862

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Actual balances provided by Rates and Regulatory - Joint Agency Asset Rider support
[3] Actual balances provided by Asset Accounting for the Distribution System Demand Response rider support
[4] Amounts above do not include Asset Retirement Obligation (ARO) or Capital Lease balance
[5] Amounts represent Asheville CC plant in service expected to be placed in service in March 2020. See NC-3405
[6] The Company adjusted the Asheville CC project costs to exclude Task Force consulting expenses noted in PS DR 125-5 from rate base

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1009
Supplemental
February Update

Accumulated Depreciation Balances

Line No.	Description	ACTUALS [1][4]															
		Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Net Change
		a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p = o - a
1	Accumulated Depreciation																
2	Steam plant	$ (2,011,905)	$ (2,019,818)	$ (2,030,802)	$ (2,045,887)	$ (2,044,204)	$ (2,059,607)	$ (2,080,807)	$ (2,105,933)	$ (2,124,886)	$ (2,142,407)	$ (2,145,509)	$ (2,154,317)	$ (2,161,285)	$ (1,835,584)	$ (1,862,933)	$ 148,972
3	Nuclear plant	(4,430,694)	(4,445,828)	(4,465,220)	(4,485,722)	(4,490,599)	(4,503,309)	(4,504,855)	(4,520,143)	(4,536,943)	(4,547,715)	(4,566,923)	(4,543,646)	(4,538,036)	(4,548,229)	(4,541,755)	(111,061)
4	Hydro plant	(46,007)	(46,412)	(48,279)	(48,734)	(48,654)	(48,747)	(49,138)	(49,480)	(49,287)	(49,302)	(49,644)	(49,397)	(48,697)	(49,055)	(47,202)	(1,195)
5	Other production plant	(671,003)	(633,115)	(674,481)	(705,483)	(714,393)	(729,565)	(741,728)	(753,183)	(730,673)	(752,679)	(763,208)	(771,014)	(781,562)	(794,155)	(796,214)	(125,211)
6	Transmission plant	(816,198)	(815,911)	(821,258)	(823,868)	(824,684)	(827,644)	(832,098)	(834,554)	(838,498)	(843,308)	(842,303)	(845,584)	(842,971)	(844,425)	(848,981)	(32,784)
7	Distribution plant	(3,235,148)	(3,227,261)	(3,226,020)	(3,228,109)	(3,228,331)	(3,228,703)	(3,238,531)	(3,240,789)	(3,251,413)	(3,249,457)	(3,253,411)	(3,258,335)	(3,224,680)	(3,228,935)	(3,249,907)	(14,758)
8	General plant	(167,536)	(169,790)	(171,749)	(170,037)	(173,564)	(177,262)	(174,792)	(179,685)	(175,082)	(173,141)	(178,333)	(181,403)	(184,244)	(187,900)	(188,350)	(20,814)
9	Intangible plant	(322,831)	(326,848)	(330,893)	(334,936)	(339,071)	(346,072)	(350,270)	(355,022)	(359,708)	(364,443)	(369,180)	(373,718)	(378,291)	(383,823)	(389,205)	(66,374)
10	Total Accumulated Depreciation (Sum L2 through L9	$ (11,701,322)	$ (11,684,983)	$ (11,768,701)	$ (11,842,776)	$ (11,863,499)	$ (11,920,910)	$ (11,972,218)	$ (12,038,788)	$ (12,066,492)	$ (12,122,451)	$ (12,168,512)	$ (12,177,415)	$ (12,159,767)	$ (11,872,107)	$ (11,924,547)	$ (223,224)
11																	
12	Direct Assignments in COS Included above																
13	Rate Difference - SC Retail	$ 24,176	$ 24,069	$ 23,962	$ 23,855	$ 23,748	$ 23,642	$ 23,535	$ 23,428	$ 23,321	$ 23,214	$ 23,107	$ 23,000	$ 22,893	$ 22,786	$ 22,679	$ (1,497)
14	Rate Difference - WHS	7,916	7,881	7,846	7,811	7,776	7,741	7,706	7,671	7,636	7,602	7,567	7,532	7,497	7,462	7,428	(488)
15	Rate Difference - NCEMPA	2,918	2,902	2,886	2,870	2,854	2,838	2,822	2,806	2,791	2,775	2,759	2,743	2,727	2,711	2,695	(223)
16	Contra AFUDC - NC Retail	238,121	238,666	239,130	239,569	240,074	240,567	240,581	240,918	241,332	242,332	241,744	242,076	242,378	242,430	245,095	6,974
17	Contra AFUDC - SC Retail	23,951	24,010	24,064	24,117	24,177	24,236	29,903	29,917	29,971	30,074	30,003	30,039	30,070	24,411	24,723	773
18	Contra AFUDC - WHS	30,312	30,379	30,438	30,496	30,560	30,624	30,642	30,696	30,753	30,913	30,850	30,904	30,946	30,949	31,300	988
19	Harris Disallowance - NC	254,434	254,851	255,268	255,685	256,102	256,519	256,936	257,353	257,770	258,187	258,604	259,021	259,438	259,855	260,272	5,838
20	Harris Disallowance - SC	32,462	32,518	32,575	32,631	32,688	32,744	32,801	32,857	32,914	32,970	33,027	33,083	33,140	33,196	33,253	791
21	Harris Disallowance - WHS	50,127	50,219	50,312	50,404	50,497	50,589	50,682	50,774	50,867	50,959	51,052	51,144	51,237	51,329	51,421	1,295
22	Harris Disallowance - PA	15,761	15,787	15,814	15,841	15,867	15,894	15,921	15,947	15,974	16,001	16,027	16,054	16,080	16,107	16,134	373
23	Production Plant - Other NC	(340,105)	(339,046)	(337,988)	(336,929)	(335,871)	(334,812)	(333,754)	(332,695)	(331,636)	(330,578)	(329,519)	(328,461)	(327,402)	(326,344)	(325,285)	14,820
24	Production Plant - Other SC	(63,159)	(62,970)	(62,781)	(62,592)	(62,403)	(62,214)	(62,025)	(61,836)	(61,647)	(61,458)	(61,268)	(61,079)	(60,890)	(60,701)	(60,512)	2,647
25	Production Plant - WHS	-	-	-	-	-	-	-	-	-	-	-	-	(434)	(434)	(434)	(434)
26	OATT - WHS	1,423	1,431	1,439	1,447	1,455	1,463	1,471	1,480	1,488	1,496	1,504	1,513	1,521	1,529	1,537	114
27	Total Direct Assignments in COS (Sum L13 through L26	$ 278,335	$ 280,697	$ 282,964	$ 285,205	$ 287,524	$ 289,831	$ 297,222	$ 299,317	$ 301,533	$ 304,486	$ 305,455	$ 307,568	$ 309,199	$ 305,286	$ 310,306	$ 31,971
28																	
29	COS Adjustments																
30	Acquisition Adjustment	$ (43,592)	$ (44,656)	$ (45,719)	$ (46,782)	$ (47,845)	$ (48,908)	$ (49,972)	$ (51,035)	$ (52,098)	$ (53,161)	$ (54,225)	$ (55,288)	$ (56,351)	$ (57,414)	$ (58,478)	$ (14,885)
31	Remove Nuclear Decommissioning ARO in 108000	96,122	96,122	96,122	96,122	96,644	96,644	97,162	97,162	97,162	97,683	97,683	97,683	98,203	98,203	98,203	2,081
32	Total COS Adjustments (Sum L30 through L31)	$ 52,530	$ 51,467	$ 50,403	$ 49,340	$ 48,799	$ 47,736	$ 47,191	$ 46,128	$ 45,064	$ 44,521	$ 43,458	$ 42,395	$ 41,852	$ 40,788	$ 39,725	$ (12,805)
33																	
34	COS Accumulated Depreciation																
35	Production Plant ((Sum L2 through L5 + L32) - Sum L13 through L25	$ (7,383,992)	$ (7,372,974)	$ (7,449,903)	$ (7,520,244)	$ (7,535,118)	$ (7,581,861)	$ (7,625,087)	$ (7,680,448)	$ (7,696,770)	$ (7,750,571)	$ (7,785,777)	$ (7,782,035)	$ (7,795,406)	$ (7,489,991)	$ (7,517,148)	$ (133,156)
36	Direct Assignments - NC (L16 + L19 + L23)	152,450	154,471	156,410	158,324	160,305	162,273	163,764	165,576	167,465	169,941	170,829	172,636	174,414	175,941	180,082	27,632
37	Direct Assignments - SC (L13 + L17 + L20 + L24)	17,429	17,627	17,819	18,012	18,210	18,408	24,213	24,366	24,559	24,800	24,868	25,043	25,212	19,692	20,143	2,714
38	Direct Assignments - WHS (L14 + L15 + L18 + L21 + L22 + L25 + L2	108,456	108,600	108,735	108,870	109,009	109,150	109,245	109,375	109,509	109,745	109,758	109,889	109,573	109,653	110,081	1,625
39	Transmission plant (L6 - L26)	(817,620)	(817,342)	(822,697)	(825,315)	(826,139)	(829,107)	(833,569)	(836,033)	(839,986)	(844,804)	(843,808)	(847,097)	(844,492)	(845,954)	(850,518)	(32,898)
40	Distribution plant (L7)	(3,235,148)	(3,227,261)	(3,226,020)	(3,228,109)	(3,228,331)	(3,228,703)	(3,238,531)	(3,240,789)	(3,251,413)	(3,249,457)	(3,253,411)	(3,258,335)	(3,224,680)	(3,228,935)	(3,249,907)	(14,758)
41	General plant (L8)	(167,536)	(169,790)	(171,749)	(170,037)	(173,564)	(177,262)	(174,792)	(179,685)	(175,082)	(173,141)	(178,333)	(181,403)	(184,244)	(187,900)	(188,350)	(20,814)
42	Intangible plant (L9)	(322,831)	(326,848)	(330,893)	(334,936)	(339,071)	(346,072)	(350,270)	(355,022)	(359,708)	(364,443)	(369,180)	(373,718)	(378,291)	(383,823)	(389,205)	(66,374)
43	Total COS Accumulated Depreciation (Sum L35 through L42	$ (11,648,793)	$ (11,633,517)	$ (11,718,298)	$ (11,793,436)	$ (11,814,700)	$ (11,873,174)	$ (11,925,027)	$ (11,992,660)	$ (12,021,428)	$ (12,077,930)	$ (12,125,054)	$ (12,135,020)	$ (12,117,915)	$ (11,831,318)	$ (11,884,821)	$ (236,029)
44																	
45	Accumulated Depreciation recovered in riders included above																
46	JAAR - Steam plant [2]	$ (19,888)														$ (26,236)	$ (6,349)
47	JAAR - Nuclear plant [2]	(90,234)														(124,077)	(33,843)
48	JAAR - Acquisition Adjustment [2]	(43,592)														(58,477)	(14,885)
49	DSDR - Transmission [3]	(101)														(114)	(13)
50	DSDR - Distribution [3]	(44,120)														(50,328)	(6,208)
51	DSDR - General plant [3]	(4,890)														(6,182)	(1,292)
52	DSDR - Intangibles [3]	(32,431)														(32,818)	(387)
53	Total Accum Depr recovered in riders (Sum L46 through L52	$ (235,256)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (298,233)	$ (62,977)

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Actual balances provided by Rates and Regulatory - Joint Agency Asset Rider suppo
[3] Actual balances provided by Asset Accounting for the Distribution System Demand Response rider suppo
[4] Amounts above do not include Asset Retirement Obligation (ARO) reserve balances in accounts 0108155,0108315,0108499, or 010864

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1010
Supplemental
February Update

Twelve Months of Depreciation Expense as of Feb. 29, 2020

Line No.	Description	ACTUALS [1][2][3] Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	12 MONTHS
		a	b	c	d	e	f	g	h	i	j	k	l	m = sum(a:l)
1	Function													
2	STEAM PLANT	$ 12,606	$ 12,709	$ 12,991	$ 13,047	$ 12,899	$ 12,979	$ 12,920	$ 13,027	$ 13,021	$ 13,120	$ 13,113	$ 11,737	$ 154,170
3	LAND RIGHTS - STEAM	3	3	3	3	3	3	3	3	3	3	3	3	30
4	NC IMPAIRMENT - STEAM	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(415)
5	WHS IMPAIRMENT - STEAM	-	-	-	-	-	-	-	-	-	-	-	-	-
6	NUCLEAR PLANT	21,842	21,897	22,143	22,204	22,265	22,287	21,695	22,338	22,325	22,486	23,405	22,856	267,743
7	LAND RIGHTS - NUCLEAR	56	56	56	56	56	56	56	56	56	56	56	56	677
8	HYDRAULIC PLANT	412	413	415	415	415	415	407	430	430	424	455	434	5,066
9	LAND RIGHTS - HYDRO	0	0	0	0	0	0	0	0	0	0	0	0	4
10	OTHER (CT's)	11,249	11,337	11,207	11,218	11,206	11,209	11,352	11,404	11,458	12,960	12,897	13,365	140,862
11	OTHER (CT's Land)	11	11	11	11	11	11	11	11	11	11	11	11	127
12	OTHER (SOLAR)	825	824	824	824	824	824	824	825	825	825	825	825	9,895
13	NC IMPAIRMENT - OTHER	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(22)
14	WHS IMPAIRMENT - OTHER	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
15	TRANSMISSION OTHER	4,040	4,046	4,094	4,149	4,180	4,195	4,162	4,225	4,295	4,323	4,435	4,398	50,540
16	TRANSMISSION RIGHT OF WAY	177	177	177	177	177	177	177	177	177	177	177	177	2,120
17	OATT CONTRA - TRANS	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(89)
18	DISTRIBUTION OTHER	15,293	14,385	14,511	15,247	14,833	14,958	14,796	15,133	15,231	15,277	15,751	15,520	180,935
19	DISTRIBUTION RIGHT OF WAY	34	35	35	35	35	35	35	35	35	35	35	35	419
20	OATT CONTRA - DISTR	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
21	GENERAL LAND AND LAND RIGHTS	2	2	2	2	2	2	2	2	2	2	2	2	27
22	GENERAL STRUCTURES AND IMPROVEMENTS	319	314	312	321	319	318	323	323	322	149	321	343	3,684
23	GENERAL FURNITURE AND EQPMT	68	68	69	69	70	70	70	69	69	17	68	74	781
24	GENERAL EDP EQUIPMENT	665	667	674	691	690	697	689	690	690	682	772	777	8,384
25	GENERAL TRANSPORTATION EQUIPMENT [4]	-	-	-	-	-	-	-	-	-	-	-	-	-
26	GENERAL STORES EQUIPMENT	9	9	9	9	9	8	8	8	8	8	8	8	98
27	GENERAL TOOLS, SHOPS & GARAGE EQPMT	377	377	379	380	381	383	377	378	379	382	390	390	4,573
28	GENERAL LABORATORY EQUIPMENT	37	37	37	37	37	37	33	33	33	33	33	33	422
29	GENERAL POWER OPERATED EQUIPMENT	28	28	28	28	30	30	30	30	30	37	37	37	375
30	GENERAL COMMUNICATION EQUIPMENT	774	781	788	791	794	809	827	850	872	847	920	973	10,026
31	OATT CONTRA - COMM EQUIP	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(7)
32	GENERAL MISCELLANEOUS EQUIPMENT	100	103	103	103	103	103	(99)	83	84	266	267	90	1,306
33	INTANGIBLE	4,043	4,135	4,121	4,197	4,752	4,789	4,735	4,737	4,538	4,574	5,532	5,400	55,553
34	Total Depreciation (Sum L2 through L33)	$ 72,924	$ 72,370	$ 72,945	$ 73,971	$ 74,049	$ 74,352	$ 73,388	$ 74,820	$ 74,847	$ 76,649	$ 79,467	$ 77,500	$ 897,282

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Amounts above do not include Asset Retirement Obligation (ARO) balances
[3] Depreciation expense on vehicles is recorded to 803 accounts, therefore it is excluded above.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1011
Supplemental
February Update

Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142

Line No.	Description	Total System		NC Retail Allocation	Total NC Retail
1	Summary of impacts to rate base				
2	Asheville CWIP Balance as of 10/30/2017	$ 169,850	[1]	60.6008% [1]	$ 102,930
3					
4	Remove Asheville CWIP in Rate Base (-L2)	$ (169,850)			$ (102,930)

[1] Docket No. E-2, Sub 1142 - NC-1200(F) - Update Adjust for Asheville base load CWIP - Oct Update

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC-1100
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts amortization expense, income taxes and rate base for the amortization of deferred environmental costs related to the removal of coal ash.

The impact to depreciation expense reflects a 5 year amortization of deferred coal ash costs. The balance of the deferral is projected through August 31, 2020. The estimated cost of removal related to the active and retired fossil plants that has already been collected from customers through depreciation rates is removed from the balance.

The impact to Rate Base includes the additional deferred costs through February of 2020 and additional ADIT on the deferred balance change.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update:

Updated Non ARO Spend and ARO spend with actuals through October 2019.

November update:

Updated Non ARO Spend and ARO spend with actuals through November 2019.

December update:

Updated Non ARO Spend and ARO spend with actuals through December 2019.

January update:

Updated actuals through January 2020 on NC 1103 and NC 1105; incorporated ADIT into the plant return calculation on NC 1105; added tab NC 1110 which estimates ADIT related to Non ARO Projects

February update:

Updated actuals through February 2020 on NC 1103, NC 1105, and NC 1110

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1100
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Application	Change
1			February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.		-	-	-
11	Depreciation and amortization	NC-1101	96,023	105,972	(9,949)
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1101	(22,248)	(24,553)	2,305
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	73,775	81,419	(7,644)
18					
19	Operating income	L4 - L17	$ (73,775)	$ (81,419)	$ 7,644
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24	**Pro Formas Impacting Rate Base Line Items**				
25					
26	Electric plant in service		$ -	$ -	$ -
27	Accumulated depreciation and amortization		-	-	-
28	Electric plant in service, net	Sum L26 through L27	-	-	-
29					
30	Add:				
31	Materials and supplies		-	-	-
32	Working capital investment	NC 1801 L26	384,091	423,886	(39,795)
33	Plant held for future use		-	-	-
34					
35	Less:				
36	Accumulated deferred taxes	NC 1801 L28	(88,991)	(98,212)	9,220
37	Operating reserves		-	-	-
38	Customer deposits		-	-	-
39					
40	Construction work in progress		-	-	-
41					
42	Total impact to rate base	Sum L28 through L40	$ 295,100	$ 325,675	$ (30,575)
43					
44	Note:				
45	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1101
Supplemental
February Update

Line No.	Description	Total Coal Ash ARO NC Retail	Total Coal Ash Non ARO NC Retail	Total NC Retail
1				
2	Projected Ending Balance at August 31, 2020	$ 440,115 [1]	$ 39,999 [2]	$ 480,114
3				
4	Balance for Amortization	$ 440,115	$ 39,999	$ 480,114
5				
6	Years to Amortize	5	5	
7				
8	Annual amortization (L4/L6) before penalty	$ 88,023	$ 8,000	$ 96,023
9				
10	Statutory tax rate			23.1693% [3]
11				
12	Impact to income taxes (-L4 x L6)			$ (22,248)
13				
14	Impact to operating income (-L8 - L12)			$ (73,775)
15				
16	Impact to Rate Base			
17				
18	Projected August 31 2020 Balance for Rate Base (L2)	$ 440,115	$ 39,999	$ 480,114
19	Less 12 months Coal Ash Deferral Amortization (-L8)	(88,023)	(8,000)	(96,023)
20	Projected coal ash def bal after one year of amortization (L18 + L19)	$ 352,092	$ 31,999	$ 384,091
21				
22	Deferred tax rate	23.1693%	23.1693%	
23	Impact to accumulated deferred income tax (-L20 x L22)	$ (81,577)	$ (7,414)	$ (88,991)
24				
25	Impact to rate base (L20 + L23)	$ 270,515	$ 24,585	$ 295,100

[1] NC-1102 - Deferral Col (s) Line 40
[2] NC-1104 - Deferral Col (r) Line 65
[3] NC-0104 - 2019 Composite Tax rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC-1102
Supplemental
February Update

	After Tax LTD Rate	After Tax Equity Rate	
2017	1.3519%	5.4060%	[5]
2018 Jan - Feb	1.6431%	5.4060%	[5]
2018 Mar - Dec	1.4871%	5.1480%	[5]
2019	1.4936%	5.1480%	[5]
2020	1.4936%	5.1480%	[5]

					ENERGY	Duke Energy Progress Coal Ash Deferral (North Carolina)									
		(a)	(b)	(c)	(d)	(e)	(f)=(a)x(d)	(g)	(h)	(i)	(j)=(e)+((f)+(g)+(h))/2	(k)	(l)	(m)=(k)+(l)	(n)=(i)+(m)
			Active Plant	Retired Coal Ash	% to NC			Active Plant	Retired Coal		NC	Compounded annually			
Line		System	COR	Plant COR		Beginning	NC	COR	Ash Plant	Ending	Balance	Deferred	Deferred		Total
No.		Spend	Offset	Offset		Balance	Spend	Offset	COR Offset	Balance	for Return	Cost of Debt	Cost of Equity	Total Return	Ending Balance
		[1]	[2]	[2]	[3]			[2]	[2]						
1	Aug-17										-				
2	Sep	$ 14,127,429	$ (284,727)	$ (773,130)	60.8102%	$ -	$ 8,590,913	$ (203,721)	$ (642,392)	$ 7,744,801	$ 3,872,400	$ 4,363	$ 17,445	$ 21,808	$ 7,766,608
3	Oct	13,925,270	(284,727)	(773,130)	60.8102%	7,744,801	8,467,979	(203,721)	(642,392)	15,366,668	11,555,734	13,018	52,059	65,077	15,453,553
4	Nov	10,319,552	(284,727)	(773,130)	60.8102%	15,366,668	6,275,336	(203,721)	(642,392)	20,795,892	18,081,280	20,370	81,456	101,826	20,984,603
5	Dec	16,303,059	(284,727)	(773,130)	60.8102%	20,795,892	9,913,917	(203,721)	(642,392)	29,863,696	25,329,794	28,536	114,111	142,647	30,195,054 [4]
6	Jan-18	11,674,153	(284,727)	(773,130)	60.8102%	30,195,054 [4]	7,099,072	(203,721)	(642,392)	36,448,013	33,321,534	45,625	150,114	195,738	36,975,109
7	Feb	14,436,895	(284,727)	(773,130)	60.8102%	36,448,013	8,779,099	(203,721)	(642,392)	44,381,000	40,414,507	55,336	182,067	237,404	44,618,404
8	Mar	16,034,812	(142,363)	(386,565)	60.8102%	44,381,000	9,750,795	(101,860)	(321,196)	53,708,740	49,044,870	60,778	210,402	271,181	54,217,324
9	Apr	12,730,875			60.8452%	53,708,740	7,746,122			61,454,862	57,581,801	71,358	247,026	318,384	62,281,830
10	May	16,344,206			60.8452%	61,454,862	9,944,659			71,399,521	66,427,191	82,319	284,973	367,292	72,593,781
11	Jun	13,183,340			60.8452%	71,399,521	8,021,425			79,420,946	75,410,233	93,451	323,510	416,961	81,032,168
12	Jul	9,840,879			60.8452%	79,420,946	5,987,699			85,408,645	82,414,796	102,132	353,559	455,691	87,475,558
13	Aug	18,186,966			60.8452%	85,408,645	11,065,890			96,474,535	90,941,590	112,699	390,139	502,838	99,044,286
14	Sep	14,296,119			60.8452%	96,474,535	8,698,497			105,173,032	100,823,784	124,945	432,534	557,479	108,300,262
15	Oct	17,794,608			60.8452%	105,173,032	10,827,159			116,000,191	110,586,612	137,044	474,417	611,460	119,738,881
16	Nov	16,803,192			60.8452%	116,000,191	10,223,930			126,224,122	121,112,156	150,087	519,571	669,658	130,632,470
17	Dec	25,439,917			60.8452%	126,224,122	15,478,960			141,703,082	133,963,602	166,013	574,704	740,717	147,047,885 [4]
18	Jan-19	20,083,956			60.8452%	147,047,885 [4]	12,220,117			159,268,002	153,157,944	190,629	657,048	847,677	160,115,679
19	Feb	22,836,296			60.8452%	159,268,002	13,894,782			173,162,784	166,215,393	206,881	713,064	919,945	174,930,406
20	Mar	24,329,058			60.8452%	173,162,784	14,803,056			187,965,840	180,564,312	224,741	774,621	999,362	190,732,824
21	Apr	31,140,483			60.8452%	187,965,840	18,947,479			206,913,319	197,439,580	245,745	847,016	1,092,760	210,773,063
22	May	38,852,313			60.8452%	206,913,319	23,639,754			230,553,073	218,733,196	272,248	938,365	1,210,613	235,623,431
23	Jun	21,872,397			61.1093%	230,553,073	13,366,073			243,919,146	237,236,110	295,278	1,017,743	1,313,021	250,302,524
24	Jul	14,696,303			61.1093%	243,919,146	8,980,811			252,899,957	248,409,552	309,185	1,065,677	1,374,862	260,658,197
25	Aug	72,417,961			61.1093%	252,899,957	44,254,124			297,154,081	275,027,019	342,314	1,179,866	1,522,180	306,434,501
26	Sep	36,936,002			61.1093%	297,154,081	22,571,340			319,725,421	308,439,751	383,902	1,323,207	1,707,108	330,712,949
27	Oct	32,420,839			61.1093%	319,725,421	19,812,154			339,537,575	329,631,498	410,278	1,414,119	1,824,397	352,349,501
28	Nov	32,053,016			61.1093%	339,537,575	19,587,380			359,124,955	349,331,265	434,798	1,498,631	1,933,429	373,870,310
29	Dec	34,963,720			61.1093%	359,124,955	21,366,091			380,491,047	369,808,001	460,284	1,586,476	2,046,761	397,283,162 [4]
30	Jan-20	13,780,946			61.1093%	397,283,162 [4]	8,421,442			405,704,604	401,493,883	499,722	1,722,409	2,222,131	407,926,735
31	Feb	26,016,157			61.1093%	405,704,604	15,898,297			421,602,901	413,653,753	514,857	1,774,575	2,289,432	426,114,464
32	Mar					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	428,447,892
33	Apr					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	430,781,319
34	May					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	433,114,747
35	Jun					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	435,448,174
36	Jul					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	437,781,602
37	Aug					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	440,115,029
38										-					
39															
40							$ 404,634,354	$ (1,324,184)	$ (4,175,545)			$ 9,207,443	$ 31,772,962	$ 40,980,404	$ 440,115,029

[1] NC-1103 - Duke Energy Progress - System Spend - Coal Ash
[2] NC 1109 Active and Retired Estimated Cost of Removal / 12
[3] NC-1106 - Allocation Factor - MWHs at Generation Level. Allocation Factors updated when new Cost of Service Factors were available.
[4] Annual compounding formula
[5] NC-1107 - Weighted Cost of Capital Rates for Duke Energy Progress

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1103
Supplemental
February Update

Duke Energy Progress - System Spend - Coal Ash including CAMA - ARO

Line No.	Month	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actual
1	January	$ -	$ 11,674,153	$ 20,083,956	$13,780,946
2	February	-	14,436,895	22,836,296	$26,016,157
3	March	-	16,034,812	24,329,058	
4	April	-	12,730,875	31,140,483	
5	May	-	16,344,206	38,852,313	
6	June	-	13,183,340	21,872,397	
7	July	-	9,840,879	14,696,303	
8	August	-	18,186,966	72,417,961	
9	September	14,127,429	14,296,119	36,936,002	
10	October	13,925,270	17,794,608	32,420,839	
11	November	10,319,552	16,803,192	32,053,016	
12	December	16,303,059	25,439,917	34,963,720	
13		$ 54,675,310	$ 186,765,961	$ 382,602,342	$ 39,797,103

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO Retail Return on Plant

	Pre Tax LTD Rate	Pre Tax Equity Rate
Jan - Feb 2018 [5]	2.1479%	7.0670%
Mar - Dec 2018 [5]	1.9440%	6.7297%
2019 [5]	1.9440%	6.7004%
2020 [5]	1.9440%	6.7004%

Line No.	Month	[1] Total Plant Additions	[2] Accumulated Depreciation	[7] Accumulated Deferred Inc Tax	Net Plant	[3] NC Retail Allocation Factor	NC Retail Net Plant	[4] Balance for Return	Pre Tax Debt Return	Pre Tax Equity Return	Total Return on Investment
		(a)	(b)	(c)	(d)= (a)+(b)+(c)	(e)	(f)	(g)	(h)	(i)	(j)=(h)+(i)
1	Jan-18	$ 37,047	$ -	($3,698)	$ 33,349	60.6008%	$ 20,209	$ 10,105	$ 18	$ 60	$ 78
2	Feb	40,325	(89)	($3,698)	36,539	60.6008%	22,143	21,176	38	125	163
3	Mar	40,473	(206)	($3,698)	36,569	60.6008%	22,161	22,152	36	124	160
4	Apr	48,443	(350)	($3,698)	44,394	61.3372%	27,230	24,696	40	138	179
5	May	5,965,821	(505)	($689,196)	5,276,120	61.3372%	3,236,226	1,631,728	2,643	9,151	11,794
6	Jun	6,050,763	(33,007)	($699,027)	5,318,728	61.3372%	3,262,361	3,249,293	5,264	18,222	23,486
7	Jul	6,104,056	(65,974)	($704,636)	5,333,446	61.3372%	3,271,388	3,266,874	5,292	18,321	23,613
8	Aug	6,204,246	(99,211)	($716,233)	5,388,801	61.3372%	3,305,341	3,288,365	5,327	18,442	23,769
9	Sep	6,275,122	(132,996)	($724,433)	5,417,692	61.3372%	3,323,063	3,314,202	5,369	18,586	23,955
10	Oct	6,302,691	(167,168)	($727,618)	5,407,905	61.3372%	3,317,059	3,320,061	5,378	18,619	23,998
11	Nov	15,144,212	(201,490)	($730,836)	14,211,886	61.3372%	8,717,177	6,017,118	9,748	33,745	43,492
12	Dec	128,515,712	(270,683)	($13,465,465)	114,779,564	61.3372%	70,402,607	39,559,892	64,087	221,856	285,943
13	Jan-19	163,503,908	(579,612)	($13,523,554)	149,400,742	61.3372%	91,638,279	81,020,443	131,253	452,394	583,647
14	Feb	166,667,791	(1,034,819)	($13,705,504)	151,927,469	61.3372%	93,188,103	92,413,191	149,709	516,008	665,717
15	Mar	210,748,372	(1,499,116)	($13,857,568)	195,391,688	61.3372%	119,847,852	106,517,978	172,559	594,765	767,324
16	Apr	347,439,735	(2,062,387)	($26,461,331)	318,916,018	61.3372%	195,614,257	157,731,054	255,524	880,724	1,136,248
17	May	374,337,308	(2,869,578)	($28,891,668)	342,576,062	61.3372%	210,126,673	202,870,465	328,650	1,132,769	1,461,419
18	Jun	377,036,268	(3,721,086)	($29,098,256)	344,216,926	61.5278%	211,789,097	210,957,885	341,752	1,177,927	1,519,678
19	Jul	380,296,416	(4,578,497)	($29,391,796)	346,326,123	61.5278%	213,086,839	212,437,968	344,150	1,186,191	1,530,341
20	Aug	382,363,991	(5,443,126)	($29,566,025)	347,354,840	61.5278%	213,719,786	213,403,313	345,713	1,191,581	1,537,295
21	Sep	383,622,726	(6,311,149)	($29,673,119)	347,638,457	61.5278%	213,894,290	213,807,038	346,367	1,193,836	1,540,203
22	Oct	386,294,290	(7,182,640)	($29,913,455)	349,198,196	61.5278%	214,853,963	214,374,126	347,286	1,197,002	1,544,288
23	Nov	387,918,438	(8,060,320)	($30,058,214)	349,799,904	61.5278%	215,224,181	215,039,072	348,363	1,200,715	1,549,078
24	Dec	387,766,356	(8,941,086)	($30,046,822)	348,778,448	61.5278%	214,595,701	214,909,941	348,154	1,199,994	1,548,148
25	Jan-20	388,617,441	(9,823,223)	($30,124,559)	348,669,658	61.5278%	214,528,765	214,562,233	347,591	1,198,052	1,545,643
26	Feb	389,390,259	(10,706,871)	($30,190,573)	348,492,816	61.5278%	214,419,958	214,474,362	347,448	1,197,562	1,545,010
27	Mar	389,390,259	(11,591,887)	($30,190,573)	347,607,799	61.5278%	213,875,427	214,147,692	346,919	1,195,738	1,542,657
28	Apr	389,390,259	(12,476,903)	($30,190,573)	346,722,783	61.5278%	213,330,896	213,603,161	346,037	1,192,697	1,538,734
29	May	389,390,259	(13,361,919)	($30,190,573)	345,837,767	61.5278%	212,786,365	213,058,630	345,155	1,189,657	1,534,812
30	Jun	389,390,259	(14,246,936)	($30,190,573)	344,952,751	61.5278%	212,241,834	212,514,100	344,273	1,186,616	1,530,889
31	Jul	389,390,259	(15,131,952)	($30,190,573)	344,067,735	61.5278%	211,697,303	211,969,569	343,391	1,183,576	1,526,966
32	Aug	389,390,259	(16,016,968)	($30,190,573)	343,182,719	61.5278%	211,152,772	211,425,038	342,509	1,180,535	1,523,044
											$ 28,131,772

[1] NC-1105 Total Plant in Service beginning on line 61
[2] NC-1105 Total Depreciation Expense beginning on line 95 + Prior Month
[3] NC 1106 Allocation Factor - Demand at Generation Level. Allocation Factors updated when new Cost of Service Factors were available.
[4] Beginning balance + additions for the month/2
[5] NC 1107 Cost of Capital
[6] NC-1105 Total Depreciation Expense beginning on line 99
[7] NC 1110 Accumulated Deferred Income Tax

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - NC Retail Deferral

	After Tax LTD Rate	After Tax Equity Rate
Jan - Feb 2018 [5]	1.6431%	5.4060%
Mar - Dec 2018 [5]	1.4871%	5.1480%
2019 [5]	1.4936%	5.1480%
2020 [5]	1.4936%	5.1480%

Line No.	Month	Beginning Balance (j)=PM(r)	Return on Investment (k)=(i)	[6] Depreciation Expense (l)	[3] NC Retail Allocation Factor (m)	NC Retail Depreciation Expense (n)=(l)*(m)	Balance for Return (o)=(j)+((k)(n))/2	After Tax Debt Return (p)	After Tax Equity Return (q)	Ending Balance (r)
33	Jan-18	$ -	$ 78	$0	60.601%	$0	$ 39	$0	$0	$78
34	Feb	78	163	89	60.601%	54	186	0	1	295
35	Mar	295	160	117	60.601%	71	411	1	2	529
36	Apr	529	179	145	61.337%	89	662	1	3	800
37	May	800	11,794	155	61.337%	95	6,744	8	29	12,726
38	Jun	12,726	23,486	32,503	61.337%	19,936	34,437	43	148	56,339
39	Jul	56,339	23,613	32,967	61.337%	20,221	78,256	97	336	100,605
40	Aug	100,605	23,769	33,237	61.337%	20,387	122,683	152	526	145,439
41	Sep	145,439	23,955	33,785	61.337%	20,723	167,778	208	720	191,045
42	Oct	191,045	23,998	34,172	61.337%	20,960	213,524	265	916	237,183
43	Nov	237,183	43,492	34,322	61.337%	21,052	269,456	334	1,156	303,218
44	Dec	303,218	285,943	69,193	61.337%	42,441	467,410	579	2,005	634,187
45	Jan-19	634,187	583,647	308,929	61.337%	189,488	1,020,755	1,270	4,379	1,412,972
46	Feb	1,412,972	665,717	455,207	61.337%	279,211	1,885,436	2,347	8,089	2,368,336
47	Mar	2,368,336	767,324	464,297	61.337%	284,787	2,894,392	3,603	12,417	3,436,467
48	Apr	3,436,467	1,136,248	563,270	61.337%	345,494	4,177,338	5,199	17,921	4,941,329
49	May	4,941,329	1,461,419	807,192	61.337%	495,109	5,919,593	7,368	25,395	6,930,620
50	Jun	6,930,620	1,519,678	851,507	61.528%	523,914	7,952,417	9,898	34,116	9,018,227
51	Jul	9,018,227	1,530,341	857,412	61.528%	527,547	10,047,170	12,505	43,102	11,131,721
52	Aug	11,131,721	1,537,295	864,629	61.528%	531,987	12,166,362	15,143	52,194	13,268,339
53	Sep	13,268,339	1,540,203	868,023	61.528%	534,076	14,305,479	17,805	61,371	15,421,794
54	Oct	15,421,794	1,544,288	871,491	61.528%	536,209	16,462,043	20,490	70,622	17,593,403
55	Nov	17,593,403	1,549,078	877,680	61.528%	540,017	18,637,951	23,198	79,957	19,785,653
56	Dec	19,785,653	1,548,148	880,766	61.528%	541,916	20,830,685	25,927	89,364	21,991,007
57	Jan-20	21,991,007	1,545,643	882,138	61.528%	542,760	23,035,209	28,671	98,821	24,206,902
58	Feb	24,206,902	1,545,010	883,648	61.528%	543,689	25,251,252	31,429	108,328	26,435,359
59	Mar	26,435,359	1,542,657	885,016	61.528%	544,531	27,478,952	34,202	117,885	28,674,633
60	Apr	28,674,633	1,538,734	885,016	61.528%	544,531	29,716,266	36,987	127,483	30,922,368
61	May	30,922,368	1,534,812	885,016	61.528%	544,531	31,962,039	39,782	137,117	33,178,609
62	Jun	33,178,609	1,530,889	885,016	61.528%	544,531	34,216,319	42,588	146,788	35,443,405
63	Jul	35,443,405	1,526,966	885,016	61.528%	544,531	36,479,153	45,404	156,496	37,716,801
64	Aug	37,716,801	1,523,044	885,016	61.528%	544,531	38,750,589	48,231	166,240	39,998,847
65			$ 28,131,772			$ 9,849,418		$ 453,734	$1,563,924	$ 39,998,847

[1] NC-1105 Total Plant in Service beginning on line 61
[2] NC-1105 Total Depreciation Expense beginning on line 95 + Prior Month
[3] NC 1106 Allocation Factor - Demand at Generation Level. Allocation Factors updated when new Cost of Service Factors were available.
[4] Beginning balance + additions for the month/2
[5] NC 1107 Cost of Capital
[6] NC-1105 Total Depreciation Expense beginning on line 99

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - Monthly Plant in Service

Line No.	Month	D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Monthly Activity
1	Jan-18	$ 600	$ 5,287	$ 33,172									$ 39,059
2	Feb-18	384	3,382										3,766
3	Mar-18	17	152										170
4	Apr-18	933	8,221										9,154
5	May-18	10	86		5,917,295								5,917,390
6	Jun-18	9	83		84,862								84,954
7	Jul-18	571	5,025		48,422								54,017
8	Aug-18	10	86	-	100,106								100,202
9	Sep-18	11	95		70,785								70,890
10	Oct-18	9	82		27,489								27,581
11	Nov-18	(46)	(404)		27,783	7,928,211	885,919						8,841,463
12	Dec-18	63	558	22,853,630	120,532	636,916	71,171	91,254,452	2,736,133				117,673,455
13	Jan-19			35,703,462	14,906	460,572	51,466	96,214	11,224				36,337,843
14	Feb-19			697,284	6,623	875,255	97,803	1,566,335	5,922				3,249,222
15	Mar-19			11,194,568	(108)	(106,205)	(11,868)	1,037,832	19,112	38,659,682			50,793,013
16	Apr-19			942,879		54,876		126,675,492	4,552	306,135	16,184,956	296	144,169,186
17	May-19			350,999		(138,986)		4,047,193	13,597	27,052,817	133,850		31,459,469
18	Jun-19			557,054		21,523		1,672,839	18,087	510,840	101,737		2,882,081
19	Jul-19			562,297		6,167		1,867,243	10,931	681,119	398,571		3,526,327
20	Aug-19			25,456				1,740,230	20,178	395,569	19,888		2,201,320
21	Sep-19			484,528				149,095	63	615,087	159,023		1,407,796
22	Oct-19			512,918				1,239,986	20,479	720,487	429,776		2,923,647
23	Nov-19	(2,572)	2,572	171,688		1,094,491	(1,094,491)	857,166	1,414	799,426	(44,723)		1,784,971
24	Dec-19			513,827				($223,420)	142	(751,628)	236,679		(224,401)
25	Jan-20			55,985				757,550		72,285	9,094		894,914
26	Feb-20			55,077				730,694		19,887			805,658
27	Total	$ -	$ 25,226	$ 74,714,824	$ 6,418,692	$ 10,832,819	$ -	$ 233,468,900	$ 2,861,832	$ 69,081,706	$ 17,628,852	$ 296	$ 415,033,147

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - Total Plant in Service

Line No.	Month	D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Balance Activity
28	Jan-18	$ 600	$ 5,287	$ 33,172	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,059
29	Feb-18	984	8,669	33,172	-	-	-	-	-	-	-	-	42,825
30	Mar-18	1,002	8,821	33,172	-	-	-	-	-	-	-	-	42,995
31	Apr-18	1,935	17,042	33,172	-	-	-	-	-	-	-	-	52,149
32	May-18	1,945	17,128	33,172	5,917,295	-	-	-	-	-	-	-	5,969,539
33	Jun-18	1,954	17,211	33,172	6,002,156	-	-	-	-	-	-	-	6,054,493
34	Jul-18	2,525	22,236	33,172	6,050,579	-	-	-	-	-	-	-	6,108,511
35	Aug-18	2,534	22,322	33,172	6,150,685	-	-	-	-	-	-	-	6,208,713
36	Sep-18	2,545	22,417	33,172	6,221,469	-	-	-	-	-	-	-	6,279,603
37	Oct-18	2,555	22,499	33,172	6,248,958	-	-	-	-	-	-	-	6,307,183
38	Nov-18	2,509	22,095	33,172	6,276,741	7,928,211	885,919	-	-	-	-	-	15,148,647
39	Dec-18	2,572	22,654	22,886,802	6,397,273	8,565,127	957,090	91,254,452	2,736,133	-	-	-	132,822,102
40	Jan-19	2,572	22,654	58,590,264	6,412,178	9,025,699	1,008,555	91,350,665	2,747,357	-	-	-	169,159,945
41	Feb-19	2,572	22,654	59,287,548	6,418,801	9,900,953	1,106,359	92,917,001	2,753,279	-	-	-	172,409,167
42	Mar-19	2,572	22,654	70,482,116	6,418,692	9,794,749	1,094,491	93,954,833	2,772,391	38,659,682	-	-	223,202,180
43	Apr-19	2,572	22,654	71,424,995	6,418,692	9,849,624	1,094,491	220,630,324	2,776,943	38,965,817	16,184,956	296	367,371,365
44	May-19	2,572	22,654	71,775,993	6,418,692	9,710,638	1,094,491	224,677,517	2,790,540	66,018,634	16,318,806	296	398,830,834
45	Jun-19	2,572	22,654	72,333,048	6,418,692	9,732,161	1,094,491	226,350,356	2,808,626	66,529,474	16,420,543	296	401,712,915
46	Jul-19	2,572	22,654	72,895,345	6,418,692	9,738,328	1,094,491	228,217,599	2,819,557	67,210,593	16,819,115	296	405,239,242
47	Aug-19	2,572	22,654	72,920,801	6,418,692	9,738,328	1,094,491	229,957,829	2,839,735	67,606,162	16,839,003	296	407,440,563
48	Sep-19	2,572	22,654	73,405,328	6,418,692	9,738,328	1,094,491	230,106,924	2,839,798	68,221,249	16,998,026	296	408,848,359
49	Oct-19	2,572	22,654	73,918,247	6,418,692	9,738,328	1,094,491	231,346,910	2,860,277	68,941,736	17,427,802	296	411,772,005
50	Nov-19	-	25,226	74,089,934	6,418,692	10,832,819	-	232,204,076	2,861,691	69,741,162	17,383,079	296	413,556,976
51	Dec-19	-	25,226	74,603,762	6,418,692	10,832,819	-	231,980,656	2,861,832	68,989,534	17,619,758	296	413,332,575
52	Jan-20	-	25,226	74,659,747	6,418,692	10,832,819	-	232,738,206	2,861,832	69,061,819	17,628,852	296	414,227,489
53	Feb-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
54	Mar-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
55	Apr-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
56	May-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
57	Jun-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
58	Jul-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
59	Aug-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	$ 415,033,147

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - Total Plant - Net of JAAR Impact

Line No.	Month	D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Balance Activity
60	JAAR Allocation %	12.94%	12.94%	3.77%				3.77%		16.17%	16.17%		
61	Jan-18	$ 523	$ 4,603	$ 31,921	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,047
62	Feb-18	857	7,547	31,921	-	-	-	-	-	-	-	-	40,325
63	Mar-18	872	7,680	31,921	-	-	-	-	-	-	-	-	40,473
64	Apr-18	1,685	14,837	31,921	-	-	-	-	-	-	-	-	48,443
65	May-18	1,693	14,912	31,921	5,917,295	-	-	-	-	-	-	-	5,965,821
66	Jun-18	1,701	14,984	31,921	6,002,156	-	-	-	-	-	-	-	6,050,763
67	Jul-18	2,198	19,359	31,921	6,050,579	-	-	-	-	-	-	-	6,104,056
68	Aug-18	2,206	19,434	31,921	6,150,685	-	-	-	-	-	-	-	6,204,246
69	Sep-18	2,216	19,516	31,921	6,221,469	-	-	-	-	-	-	-	6,275,122
70	Oct-18	2,224	19,588	31,921	6,248,958	-	-	-	-	-	-	-	6,302,691
71	Nov-18	2,184	19,236	31,921	6,276,741	7,928,211	885,919	-	-	-	-	-	15,144,212
72	Dec-18	2,239	19,723	22,023,970	6,397,273	8,565,127	957,090	87,814,159	2,736,133	-	-	-	128,515,712
73	Jan-19	2,239	19,723	56,381,411	6,412,178	9,025,699	1,008,555	87,906,745	2,747,357	-	-	-	163,503,908
74	Feb-19	2,239	19,723	57,052,408	6,418,801	9,900,953	1,106,359	89,414,030	2,753,279	-	-	-	166,667,791
75	Mar-19	2,239	19,723	67,824,940	6,418,692	9,794,749	1,094,491	90,412,735	2,772,391	32,408,411	-	-	210,748,372
76	Apr-19	2,239	19,723	68,732,273	6,418,692	9,849,624	1,094,491	212,312,561	2,776,943	32,665,044	13,567,849	296	347,439,735
77	May-19	2,239	19,723	69,070,039	6,418,692	9,710,638	1,094,491	216,207,175	2,790,540	55,343,421	13,680,055	296	374,337,308
78	Jun-19	2,239	19,723	69,606,092	6,418,692	9,732,161	1,094,491	217,816,948	2,808,626	55,771,658	13,765,342	296	377,036,268
79	Jul-19	2,239	19,723	70,147,190	6,418,692	9,738,328	1,094,491	219,613,796	2,819,557	56,342,640	14,099,464	296	380,296,416
80	Aug-19	2,239	19,723	70,171,686	6,418,692	9,738,328	1,094,491	221,288,419	2,839,735	56,674,245	14,116,136	296	382,363,991
81	Sep-19	2,239	19,723	70,637,947	6,418,692	9,738,328	1,094,491	221,431,893	2,839,798	57,189,873	14,249,445	296	383,622,726
82	Oct-19	2,239	19,723	71,131,529	6,418,692	9,738,328	1,094,491	222,625,131	2,860,277	57,793,858	14,609,726	296	386,294,290
83	Nov-19	-	21,962	71,296,744	6,418,692	10,832,819	-	223,449,982	2,861,691	58,464,016	14,572,235	296	387,918,438
84	Dec-19	-	21,962	71,791,200	6,418,692	10,832,819	-	223,234,985	2,861,832	57,833,926	14,770,643	296	387,766,356
85	Jan-20	-	21,962	71,845,074	6,418,692	10,832,819	-	223,963,975	2,861,832	57,894,523	14,778,266	296	388,617,441
86	Feb-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
87	Mar-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
88	Apr-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
89	May-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
90	Jun-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
91	Jul-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
92	Aug-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	$ 389,390,259

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - System Depreciation Expense (Net of JAAR)

		D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Balance Activity
93	Depr Rate Prior To 3/16/2018	0.45%	0.45%	3.26%									
94	Depr Rate Beg. 3/16/2018	3.05%	1.33%	5.03%	6.56%	4.74%	4.61%	1.91%	1.90%	1.95%	4.02%	5.04%	
95	Jan-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Feb-18	0	2	87	-	-	-	-	-	-	-	-	89
97	Mar-18	1	6	110	-	-	-	-	-	-	-	-	117
98	Apr-18	2	9	134	-	-	-	-	-	-	-	-	145
99	May-18	4	16	134	-	-	-	-	-	-	-	-	155
100	Jun-18	4	17	134	32,348	-	-	-	-	-	-	-	32,503
101	Jul-18	4	17	134	32,812	-	-	-	-	-	-	-	32,967
102	Aug-18	6	21	134	33,076	-	-	-	-	-	-	-	33,237
103	Sep-18	6	22	134	33,624	-	-	-	-	-	-	-	33,785
104	Oct-18	6	22	134	34,011	-	-	-	-	-	-	-	34,172
105	Nov-18	6	22	134	34,161	-	-	-	-	-	-	-	34,322
106	Dec-18	6	21	134	34,313	31,316	3,403	-	-	-	-	-	69,193
107	Jan-19	6	22	92,317	34,972	33,832	3,677	139,771	4,332	-	-	-	308,929
108	Feb-19	6	22	236,332	35,053	35,652	3,875	139,918	4,350	-	-	-	455,207
109	Mar-19	6	22	239,145	35,089	39,109	4,250	142,317	4,359	-	-	-	464,297
110	Apr-19	6	22	284,300	35,089	38,689	4,205	143,907	4,390	52,664	-	-	563,270
111	May-19	6	22	288,103	35,089	38,906	4,205	337,931	4,397	53,081	45,452	1	807,192
112	Jun-19	6	22	289,519	35,089	38,357	4,205	344,130	4,418	89,933	45,828	1	851,507
113	Jul-19	6	22	291,766	35,089	38,442	4,205	346,692	4,447	90,629	46,114	1	857,412
114	Aug-19	6	22	294,034	35,089	38,466	4,205	349,552	4,464	91,557	47,233	1	864,629
115	Sep-19	6	22	294,136	35,089	38,466	4,205	352,217	4,496	92,096	47,289	1	868,023
116	Oct-19	6	22	296,091	35,089	38,466	4,205	352,446	4,496	92,934	47,736	1	871,491
117	Nov-19	6	22	298,160	35,089	38,466	4,205	354,345	4,529	93,915	48,943	1	877,680
118	Dec-19	-	24	298,852	35,089	42,790	-	355,658	4,531	95,004	48,817	1	880,766
119	Jan-20	-	24	300,925	35,089	42,790	-	355,316	4,531	93,980	49,482	1	882,138
120	Feb-20	-	24	301,151	35,089	42,790	-	356,476	4,531	94,079	49,507	1	883,648
121	Mar-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
122	Apr-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
123	May-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
124	Jun-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
125	Jul-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
126	Aug-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	$ 885,016

Source: Duke Energy Asset Accounting

Depreciation Expense = Prior month Total Plant Net of JAAR * Depreciation Rate /12

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1106
Supplemental
February Update

Duke Energy Progress - Cost of Service - Allocation Factors

Line No.	Allocation Factor	NC Retail 2016	NC Retail 2017	NC Retail 2018
1	Allocation Factor - DPAll Demand at Generation Level	60.6008%	61.3372%	61.5278%
2	Allocation Factor - Energy @ Prod. Output MWHs at Generation	60.8102%	60.8452%	61.1093%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1107
Supplemental
February Update

Cost of debt and Equity for coal ash deferral periods

Sep 2017 - Dec 2017

	Capitalization Ratio [1]	Approved Cost Rate [1]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	47.00%	4.57%	2.1479%	1.3519%	2.1479%	
EQUITY	53.00%	10.20%	5.4060%	5.4060%	7.0670%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.5539%	6.7579%	9.2149%	
Return on Equity		2.188%				
Effective State and Federal Income Tax Rate		37.06% (e)				

Jan-Feb 2018

	Capitalization Ratio [1]	Approved Cost Rate [1]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	47.00%	4.57%	2.1479%	1.6431%	2.1479%	
EQUITY	53.00%	10.20%	5.4060%	5.4060%	7.0670%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.5539%	7.0491%	9.2149%	
Return on Equity		2.479%				
Effective State and Federal Income Tax Rate		23.50% [3]				

Mar - Dec 2018

	Capitalization Ratio [2]	Approved Cost Rate [2]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	48.00%	4.05%	1.9440%	1.4871%	1.9440%	
EQUITY	52.00%	9.90%	5.1480%	5.1480%	6.7297%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.0920%	6.6351%	8.6737%	
Return on Equity		2.585%				
Effective State and Federal Income Tax Rate		23.50% [3]				

2019

	Capitalization Ratio [2]	Approved Cost Rate [2]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	48.00%	4.05%	1.9440%	1.4936%	1.9440%	
EQUITY	52.00%	9.90%	5.1480%	5.1480%	6.7004%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.0920%	6.6416%	8.6444%	
Return on Equity		2.592%				
Effective State and Federal Income Tax Rate		23.17% [4]				

[1] Cost of capital rates from Docket No. E-2, Sub 1023
[2] Cost of capital rates from Docket No. E-2, Sub 1142
[3] Duke Energy Accounting
[4] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC-1108
Supplemental
February Update

Depreciation Rates

Line No.	Depreciation Rate	Prior to Mar 16 2018	Beg. Mar 16 2018 {1}
1	D FOS 315 ROXBORO #4	0.45%	3.05%
2	D FOS 311 ROXBORO COMMON	3.26%	5.03%
3	D FOS 312 ROXBORO #3-50121		4.74%
4	D FOS 312 ROXBORO #4	0.45%	1.33%
5	D FOS 312 ROXBORO #1		6.56%
6	D FOS 315 ROXBORO #3-50121		4.61%
7	D FOS 312 ROXBORO COMMON-50121		1.91%
8	D FOS 312 ROXBORO #2-50121		5.04%
9	D FOS 311 MAYO #1-50121		1.95%
10	D FOS 312 MAYO #1-50121		4.02%
11	D TRN 353-BU-Transmission 50126		1.90%

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC 1109
Supplemental
February Update

Estimate of Cost of Removal for Closure of Ash Ponds

Line	Plant	Decommissioning Amount for Closure of Ash Ponds [1]											
1		(a)	(b)	(c)	(d)	(e)	(f)	(g)		(h) = [3] x (d)/(g)	(k)=[3] x (d)/(g)	(j)=[3] x (d)/(g)	(k) x (j)
2	Plant	Closure of Ash Ponds [2]	Project Indirects Adder (5%) [2]	Contingency (10%) [2]	Total	Est. Retirement Date per Depr Study	Depr Study Implementation Date	Retail Recovery Period (in years) [4]	Wholesale Recovery Period (in years) [5]	Annual Retail COR for Ash Pond Closure	NC Annual Retail COR	Wholesale/ Remaining Annual COR	Annual COR for Closure of Ash Ponds
3													
4	Cape Fear	$ 22,000	$ 1,100	$ 2,200	$ 25,300		July 1, 2012	10	13	$ 1,882	$ 1,631	$ 505	$ 2,136
5	Lee	43,000	2,150	4,300	49,450		July 1, 2012	10	27	3,678	3,187	464	3,651
6	Robinson	11,000	550	1,100	12,650		July 1, 2012	10	27	941	815	120	935
7	Sutton	21,000	1,050	2,100	24,150		July 1, 2012	10	16	1,796	1,557	395	1,952
8	Weatherspoon	7,000	350	700	8,050		July 1, 2012	10	24	599	519	85	604
9	Subtotal Early-Retired Plants	104,000	5,200	10,400	119,600					8,895	7,709	1,569	9,278
10	Asheville	9,000	450	900	10,350	2033	July 1, 2012	21	21	367	318	126	444
11	Mayo	19,000	950	1,900	21,850	2035	July 1, 2012	23	23	707	612	243	856
12	Roxboro	47,000	2,350	4,700	54,050	2035	July 1, 2012	23	23	1,748	1,515	602	2,117
13	Subtotal active plants	75,000	3,750	7,500	86,250					2,821	2,445	972	3,417
14	Total	$ 179,000	$ 8,950	$ 17,900	$ 205,850					$ 11,716	$ 10,153	$ 2,541	$ 12,694

[1] Amounts reflect 100% system amounts.
[2] Amounts per DEP Dismantlement Study
[3] Based on allocation factors from the 2012 NC rate case

COR for Ash Pond Closure	74.371%
NC Retail	64.454%
Wholesale	25.629%

[4] Remaining Life per Depreciation Study
[5] Remaining Life per FERC Settlement Agreement

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description / Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
201801								5287.06	600.28								33171.55	39,059
201802								3,382	384									3,766
201803								152	17									170
201804								8,221	933									9,154
201805				5,917,295				86	10									5,917,390
201806				84,862				83	9									84,954
201807				48,422				5,025	571									54,017
201808				100,106				86	10								-	100,202
201809				70,785				95	11									70,890
201810				27,489				82	9									27,581
201811				27,783		7,928,211	885,919	(404)	(46)									8,841,463
201812		2,736,133	91,254,452	120,532		636,916	71,171	558	63							22,853,630		117,673,455
201901		11,224	96,214	14,906		460,572	51,466								35,294,091	409,371		36,337,843
201902		5,922	1,566,335	6,623		875,255	97,803								638,355	58,929		3,249,222
201903		19,112	1,037,832	(108)		(106,205)	(11,868)			6,700,621			38,659,682		4,167,608	326,339		50,793,013
201904		4,552	1,602,076		296	54,876				198,486	16,184,956		306,135	125,073,416	625,589	118,804		144,169,186
201905		13,597	690,918			(138,986)				157,701	133,850	26,796,814	256,002	3,356,275	536,750	(343,452)		31,459,469
201906		18,087	(225,274)			21,523				175,967	101,737	429,079	81,761	1,898,113	191,077	190,010		2,882,081
201907		10,931	101,010			6,167				30,652	398,571	590,493	90,626	1,766,232	101,796	429,849		3,526,327
201908		20,178	432,993							28,874	19,888	206,809	188,760	1,307,237	70,465	(73,883)		2,201,320
201909	(318,728)	63								(14,927)	159,023	451,967	163,120	467,823	20,131	479,324		1,407,796
201910	109,744	20,479								48,993	429,776	742,253	(21,766)	1,130,242	138,786	325,140		2,923,647
201911		1,414	14,208			1,094,491	(1,094,491)	2,572	(2,572)	78,554	(44,723)	789,320	10,105	842,958	2,096	91,039		1,784,971
201912		142	(17,606)							31,962	236,679	(781,554)	29,926	(205,814)	22,064	459,801		(224,401)
202001			(92)							9,076	9,094	72,150	135	757,642	12,230	34,679		894,914
202002										18,111		19,887		730,694	43,218	(6,252)		805,658
Grand Total	(208,984)	2,861,832	96,553,065	6,418,692	296	10,832,819	-	25,226	-	7,464,069	17,628,852	29,317,218	39,764,487	137,124,819	41,864,255	25,353,328	33,172	415,033,147

Cumulative Plant additions

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description / Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
201801	-	-	-	-	-	-	-	5,287	600	-	-	-	-	-	-	-	33,172	39,059
201802	-	-	-	-	-	-	-	8,669	984	-	-	-	-	-	-	-	33,172	42,825
201803	-	-	-	-	-	-	-	8,821	1,002	-	-	-	-	-	-	-	33,172	42,995
201804	-	-	-	-	-	-	-	17,042	1,935	-	-	-	-	-	-	-	33,172	52,149
201805	-	-	-	5,917,295	-	-	-	17,128	1,945	-	-	-	-	-	-	-	33,172	5,969,539
201806	-	-	-	6,002,156	-	-	-	17,211	1,954	-	-	-	-	-	-	-	33,172	6,054,493
201807	-	-	-	6,050,579	-	-	-	22,236	2,525	-	-	-	-	-	-	-	33,172	6,108,511
201808	-	-	-	6,150,685	-	-	-	22,322	2,534	-	-	-	-	-	-	-	33,172	6,208,713
201809	-	-	-	6,221,469	-	-	-	22,417	2,545	-	-	-	-	-	-	-	33,172	6,279,603
201810	-	-	-	6,248,958	-	-	-	22,499	2,555	-	-	-	-	-	-	-	33,172	6,307,183
201811	-	-	-	6,276,741	-	7,928,211	885,919	22,095	2,509	-	-	-	-	-	-	-	33,172	15,148,647
201812	-	2,736,133	91,254,452	6,397,273	-	8,565,127	957,090	22,654	2,572	-	-	-	-	-	-	22,853,630	33,172	132,822,102
201901	-	2,747,357	91,350,665	6,412,178	-	9,025,699	1,008,555	22,654	2,572	-	-	-	-	-	35,294,091	23,263,001	33,172	169,159,945
201902	-	2,753,279	92,917,001	6,418,801	-	9,900,953	1,106,359	22,654	2,572	-	-	-	-	-	35,932,446	23,321,930	33,172	172,409,167
201903	-	2,772,391	93,954,833	6,418,692	-	9,794,749	1,094,491	22,654	2,572	6,700,621	-	-	38,659,682	-	40,100,055	23,648,269	33,172	223,202,180
201904	-	2,776,943	95,556,908	6,418,692	296	9,849,624	1,094,491	22,654	2,572	6,899,107	16,184,956	-	38,965,817	125,073,416	40,725,643	23,767,073	33,172	367,371,365
201905	-	2,790,540	96,247,826	6,418,692	296	9,710,638	1,094,491	22,654	2,572	7,056,807	16,318,806	26,796,814	39,221,819	128,429,691	41,262,394	23,423,621	33,172	398,830,834
201906	-	2,808,626	96,022,552	6,418,692	296	9,732,161	1,094,491	22,654	2,572	7,232,775	16,420,543	27,225,893	39,303,580	130,327,804	41,453,471	23,613,631	33,172	401,712,915
201907	-	2,819,557	96,123,562	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,263,427	16,819,115	27,816,387	39,394,206	132,094,037	41,555,267	24,043,479	33,172	405,239,242
201908	-	2,839,735	96,556,555	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,292,301	16,839,003	28,023,196	39,582,966	133,401,274	41,625,731	23,969,597	33,172	407,440,563
201909	(318,728)	2,839,798	96,556,555	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,277,373	16,998,026	28,475,163	39,746,086	133,869,097	41,645,862	24,448,921	33,172	408,848,359
201910	(208,984)	2,860,277	96,556,555	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,326,367	17,427,802	29,217,416	39,724,321	134,999,339	41,784,648	24,774,061	33,172	411,772,005
201911	(208,984)	2,861,691	96,570,763	6,418,692	296	10,832,819	-	25,226	-	7,404,920	17,383,079	30,006,736	39,734,426	135,842,298	41,786,744	24,865,099	33,172	413,556,976
201912	(208,984)	2,861,832	96,553,157	6,418,692	296	10,832,819	-	25,226	-	7,436,882	17,619,758	29,225,182	39,764,352	135,636,484	41,808,807	25,324,901	33,172	413,332,575
202001	(208,984)	2,861,832	96,553,065	6,418,692	296	10,832,819	-	25,226	-	7,445,958	17,628,852	29,297,331	39,764,487	136,394,125	41,821,037	25,359,580	33,172	414,227,489
202002	(208,984)	2,861,832	96,553,065	6,418,692	296	10,832,819	-	25,226	-	7,464,069	17,628,852	29,317,218	39,764,487	137,124,819	41,864,255	25,353,328	33,172	415,033,147

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Total Plant - Net of JAAR Impact

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description																		
Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
JAAR %	3.77%		3.77%					12.94%	12.94%	3.77%	16.17%	16.17%	16.17%	3.77%	3.77%	3.77%	3.77%	
201801	-	-	-	-	-	-	-	4,603	523	-	-	-	-	-	-	-	31,921	37,047
201802	-	-	-	-	-	-	-	7,547	857	-	-	-	-	-	-	-	31,921	40,325
201803	-	-	-	-	-	-	-	7,680	872	-	-	-	-	-	-	-	31,921	40,473
201804	-	-	-	-	-	-	-	14,837	1,685	-	-	-	-	-	-	-	31,921	48,443
201805	-	-	-	5,917,295	-	-	-	14,912	1,693	-	-	-	-	-	-	-	31,921	5,965,821
201806	-	-	-	6,002,156	-	-	-	14,984	1,701	-	-	-	-	-	-	-	31,921	6,050,763
201807	-	-	-	6,050,579	-	-	-	19,359	2,198	-	-	-	-	-	-	-	31,921	6,104,056
201808	-	-	-	6,150,685	-	-	-	19,434	2,206	-	-	-	-	-	-	-	31,921	6,204,246
201809	-	-	-	6,221,469	-	-	-	19,516	2,216	-	-	-	-	-	-	-	31,921	6,275,122
201810	-	-	-	6,248,958	-	-	-	19,588	2,224	-	-	-	-	-	-	-	31,921	6,302,691
201811	-	-	-	6,276,741	-	7,928,211	885,919	19,236	2,184	-	-	-	-	-	-	-	31,921	15,144,212
201812	-	2,736,133	87,814,159	6,397,273	-	8,565,127	957,090	19,723	2,239	-	-	-	-	-	-	21,992,049	31,921	128,515,712
201901	-	2,747,357	87,906,745	6,412,178	-	9,025,699	1,008,555	19,723	2,239	-	-	-	-	-	33,963,504	22,385,986	31,921	163,503,908
201902	-	2,753,279	89,414,030	6,418,801	-	9,900,953	1,106,359	19,723	2,239	-	-	-	-	-	34,577,793	22,442,694	31,921	166,667,791
201903	-	2,772,391	90,412,735	6,418,692	-	9,794,749	1,094,491	19,723	2,239	6,448,007	-	-	32,408,411	-	38,588,283	22,756,729	31,921	210,748,372
201904	-	2,776,943	91,954,413	6,418,692	296	9,849,624	1,094,491	19,723	2,239	6,639,010	13,567,849	-	32,665,044	120,358,148	39,190,287	22,871,055	31,921	347,439,735
201905	-	2,790,540	92,619,283	6,418,692	296	9,710,638	1,094,491	19,723	2,239	6,790,766	13,680,055	22,463,770	32,879,651	123,587,892	39,706,801	22,540,550	31,921	374,337,308
201906	-	2,808,626	92,402,502	6,418,692	296	9,732,161	1,094,491	19,723	2,239	6,960,099	13,765,342	22,823,466	32,948,191	125,414,446	39,890,675	22,723,397	31,921	377,036,268
201907	-	2,819,557	92,499,704	6,418,692	296	9,738,328	1,094,491	19,723	2,239	6,989,596	14,099,464	23,318,477	33,024,163	127,114,092	39,988,633	23,137,040	31,921	380,296,416
201908	-	2,839,735	92,916,373	6,418,692	296	9,738,328	1,094,491	19,723	2,239	7,017,381	14,116,136	23,491,845	33,182,400	128,372,046	40,056,441	23,065,943	31,921	382,363,991
201909	(306,712)	2,839,798	92,916,373	6,418,692	296	9,738,328	1,094,491	19,723	2,239	7,003,016	14,249,445	23,870,729	33,319,144	128,822,232	40,075,813	23,527,197	31,921	383,622,726
201910	(201,106)	2,860,277	92,916,373	6,418,692	296	9,738,328	1,094,491	19,723	2,239	7,050,163	14,609,726	24,492,960	33,300,898	129,909,864	40,209,367	23,840,078	31,921	386,294,290
201911	(201,106)	2,861,691	92,930,045	6,418,692	296	10,832,819	-	21,962	-	7,125,755	14,572,235	25,154,647	33,309,369	130,721,043	40,211,383	23,927,685	31,921	387,918,438
201912	(201,106)	2,861,832	92,913,103	6,418,692	296	10,832,819	-	21,962	-	7,156,512	14,770,643	24,499,470	33,334,457	130,522,988	40,232,615	24,370,152	31,921	387,766,356
202001	(201,106)	2,861,832	92,913,014	6,418,692	296	10,832,819	-	21,962	-	7,165,245	14,778,266	24,559,953	33,334,570	131,252,067	40,244,384	24,403,524	31,921	388,617,441
202002	(201,106)	2,861,832	92,913,014	6,418,692	296	10,832,819	-	21,962	-	7,182,674	14,778,266	24,576,624	33,334,570	131,955,214	40,285,973	24,397,507	31,921	389,390,259

Depreciation Expense

Project	20087848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
Depr Rate Prior To 3/16/2018								0.45%	0.45%	3.26%					3.26%	3.26%	3.26%	
Depr Rate Beg. 3/16/2018	1.91%	1.90%	1.91%	6.56%	5.04%	4.74%	4.61%	1.33%	3.05%	5.03%	4.02%	1.95%	1.95%	1.91%	5.03%	5.03%	5.03%	
201801																		
201802	-	-	-	-	-	-	-	2	0	-	-	-	-	-	-	-	87	89
201803	-	-	-	-	-	-	-	6	1	-	-	-	-	-	-	-	110	117
201804	-	-	-	-	-	-	-	9	2	-	-	-	-	-	-	-	134	145
201805	-	-	-	-	-	-	-	16	4	-	-	-	-	-	-	-	134	155
201806	-	-	-	32,348	-	-	-	17	4	-	-	-	-	-	-	-	134	32,503
201807	-	-	-	32,812	-	-	-	17	4	-	-	-	-	-	-	-	134	32,967
201808	-	-	-	33,077	-	-	-	21	6	-	-	-	-	-	-	-	134	33,237
201809	-	-	-	33,624	-	-	-	22	6	-	-	-	-	-	-	-	134	33,785
201810	-	-	-	34,011	-	-	-	22	6	-	-	-	-	-	-	-	134	34,172
201811	-	-	-	34,161	-	-	-	22	6	-	-	-	-	-	-	-	134	34,322
201812	-	-	-	34,313	-	31,316	3,403	21	6	-	-	-	-	-	-	-	134	69,193
201901	-	4,332	139,771	34,972	-	33,832	3,677	22	6	-	-	-	-	-	-	92,183	134	308,929
201902	-	4,350	139,918	35,053	-	35,652	3,875	22	6	-	-	-	-	-	142,364	93,835	134	455,207
201903	-	4,359	142,317	35,089	-	39,109	4,250	22	6	-	-	-	-	-	144,939	94,072	134	464,297
201904	-	4,390	143,907	35,089	-	38,689	4,205	22	6	27,028	-	-	52,664	-	161,749	95,389	134	563,270
201905	-	4,397	146,361	35,089	1	38,906	4,205	22	6	27,829	45,452	-	53,081	191,570	164,273	95,868	134	807,192
201906	-	4,418	147,419	35,089	1	38,357	4,205	22	6	28,465	45,828	36,504	53,429	196,711	166,438	94,482	134	851,507
201907	-	4,447	147,074	35,089	1	38,442	4,205	22	6	29,174	46,114	37,088	53,541	199,618	167,208	95,249	134	857,412
201908	-	4,464	147,229	35,089	1	38,466	4,205	22	6	29,298	47,233	37,893	53,664	202,323	167,619	96,983	134	864,629
201909	-	4,496	147,892	35,089	1	38,466	4,205	22	6	29,415	47,289	38,174	53,921	204,326	167,903	96,685	134	868,023
201910	(488)	4,496	147,892	35,089	1	38,466	4,205	22	6	29,354	47,736	38,790	54,144	205,042	167,984	98,618	134	871,491
201911	(320)	4,529	147,892	35,089	1	38,466	4,205	22	6	29,552	48,943	39,801	54,114	206,773	168,544	99,930	134	877,680
201912	(320)	4,531	147,914	35,089	1	42,790	-	24	-	29,869	48,817	40,876	54,128	208,064	168,553	100,297	134	880,766
202001	(320)	4,531	147,887	35,089	1	42,790	-	24	-	29,998	49,482	39,812	54,168	207,749	168,642	102,152	134	882,138
202002	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,034	49,507	39,910	54,169	208,910	168,691	102,291	134	883,648
202003	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202004	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202005	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202006	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202007	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202008	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
																		-

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Accumulated Depreciation

Project	20087848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
201802	-	-	-	-	-	-	-	(2)	(0)	-	-	-	-	-	-	-	(87)	(89)
201803	-	-	-	-	-	-	-	(7)	(1)	-	-	-	-	-	-	-	(197)	(206)
201804	-	-	-	-	-	-	-	(16)	(4)	-	-	-	-	-	-	-	(331)	(350)
201805	-	-	-	-	-	-	-	(32)	(8)	-	-	-	-	-	-	-	(465)	(505)
201806	-	-	-	(32,348)	-	-	-	(49)	(12)	-	-	-	-	-	-	-	(599)	(33,007)
201807	-	-	-	(65,160)	-	-	-	(65)	(17)	-	-	-	-	-	-	-	(732)	(65,974)
201808	-	-	-	(98,236)	-	-	-	(87)	(22)	-	-	-	-	-	-	-	(866)	(99,211)
201809	-	-	-	(131,860)	-	-	-	(108)	(28)	-	-	-	-	-	-	-	(1,000)	(132,996)
201810	-	-	-	(165,871)	-	-	-	(130)	(33)	-	-	-	-	-	-	-	(1,134)	(167,168)
201811	-	-	-	(200,032)	-	-	-	(152)	(39)	-	-	-	-	-	-	-	(1,268)	(201,490)
201812	-	-	-	(234,344)	-	(31,316)	(3,403)	(173)	(45)	-	-	-	-	-	-	-	(1,401)	(270,683)
201901	-	(4,332)	(139,771)	(269,316)	-	(65,149)	(7,080)	(195)	(50)	-	-	-	-	-	-	(92,183)	(1,535)	(579,612)
201902	-	(8,682)	(279,689)	(304,369)	-	(100,800)	(10,955)	(217)	(56)	-	-	-	-	-	(142,364)	(186,018)	(1,669)	(1,034,819)
201903	-	(13,042)	(422,006)	(339,459)	-	(139,909)	(15,205)	(239)	(62)	-	-	-	-	-	(287,302)	(280,090)	(1,803)	(1,499,116)
201904	-	(17,431)	(565,913)	(374,548)	-	(178,598)	(19,410)	(261)	(67)	(27,028)	-	-	(52,664)	-	(449,051)	(375,479)	(1,937)	(2,062,386)
201905	-	(21,828)	(712,274)	(409,637)	(1)	(217,504)	(23,614)	(282)	(73)	(54,856)	(45,452)	-	(105,744)	(191,570)	(613,324)	(471,347)	(2,070)	(2,869,578)
201906	-	(26,246)	(859,693)	(444,725)	(3)	(255,861)	(27,819)	(304)	(79)	(83,321)	(91,280)	(36,504)	(159,174)	(388,281)	(779,762)	(565,829)	(2,204)	(3,721,086)
201907	-	(30,693)	(1,006,767)	(479,814)	(4)	(294,303)	(32,024)	(326)	(84)	(112,495)	(137,394)	(73,592)	(212,715)	(587,899)	(946,970)	(661,078)	(2,338)	(4,578,497)
201908	-	(35,158)	(1,153,996)	(514,903)	(5)	(332,770)	(36,228)	(348)	(90)	(141,794)	(184,628)	(111,484)	(266,379)	(790,222)	(1,114,589)	(758,061)	(2,472)	(5,443,126)
201909	-	(39,654)	(1,301,888)	(549,992)	(6)	(371,236)	(40,433)	(370)	(96)	(171,208)	(231,917)	(149,659)	(320,300)	(994,548)	(1,282,492)	(854,746)	(2,606)	(6,311,149)
201910	488	(44,150)	(1,449,780)	(585,081)	(8)	(409,703)	(44,638)	(392)	(102)	(200,562)	(279,652)	(188,448)	(374,444)	(1,199,590)	(1,450,477)	(953,364)	(2,739)	(7,182,640)
201911	808	(48,679)	(1,597,672)	(620,170)	(9)	(448,169)	(48,842)	(414)	(107)	(230,114)	(328,595)	(228,250)	(428,558)	(1,406,363)	(1,619,021)	(1,053,293)	(2,873)	(8,060,320)
201912	1,128	(53,210)	(1,745,585)	(655,259)	(10)	(490,959)	(48,842)	(438)	(107)	(259,983)	(377,412)	(269,126)	(482,686)	(1,614,427)	(1,787,574)	(1,153,590)	(3,007)	(8,941,086)
202001	1,448	(57,741)	(1,893,472)	(690,347)	(11)	(533,748)	(48,842)	(462)	(107)	(289,981)	(426,893)	(308,937)	(536,854)	(1,822,176)	(1,956,216)	(1,255,742)	(3,141)	(9,823,223)
202002	1,769	(62,272)	(2,041,358)	(725,436)	(13)	(576,538)	(48,842)	(487)	(107)	(320,015)	(476,401)	(348,847)	(591,023)	(2,031,086)	(2,124,907)	(1,358,033)	(3,275)	(10,706,871)
202003	2,089	(66,804)	(2,189,245)	(760,525)	(14)	(619,327)	(48,842)	(511)	(107)	(350,122)	(525,908)	(388,784)	(645,191)	(2,241,114)	(2,293,772)	(1,460,299)	(3,408)	(11,591,887)
202004	2,409	(71,335)	(2,337,132)	(795,614)	(15)	(662,117)	(48,842)	(535)	(107)	(380,230)	(575,415)	(428,721)	(699,360)	(2,451,143)	(2,462,637)	(1,562,566)	(3,542)	(12,476,903)
202005	2,729	(75,866)	(2,485,018)	(830,703)	(16)	(704,907)	(48,842)	(560)	(107)	(410,337)	(624,922)	(468,658)	(753,529)	(2,661,172)	(2,631,503)	(1,664,832)	(3,676)	(13,361,919)
202006	3,049	(80,397)	(2,632,905)	(865,792)	(18)	(747,696)	(48,842)	(584)	(107)	(440,445)	(674,429)	(508,595)	(807,697)	(2,871,201)	(2,800,368)	(1,767,098)	(3,810)	(14,246,936)
202007	3,369	(84,929)	(2,780,791)	(900,880)	(19)	(790,486)	(48,842)	(608)	(107)	(470,552)	(723,937)	(548,532)	(861,866)	(3,081,229)	(2,969,234)	(1,869,364)	(3,944)	(15,131,952)
202008	3,689	(89,460)	(2,928,678)	(935,969)	(20)	(833,276)	(48,842)	(633)	(107)	(500,659)	(773,444)	(588,469)	(916,035)	(3,291,258)	(3,138,099)	(1,971,631)	(4,077)	(16,016,968)

Tax Basis for Bonus Depreciation ADIT

Project	20087848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
Bonus Depr Eligibl	#N/A	NO	#N/A	#N/A	#N/A	#N/A	#N/A	No	No	NO	YES	YES	NO	YES	NO	YES	YES	
Inititial In Service `	#N/A	2018	#N/A	#N/A	#N/A	#N/A	#N/A	2018	2018	2019	2019	2019	2019	2019	2019	2018	2018	
Bonus Depr %	50%		50%	50%	50%						40%	40%		40%		50%	50%	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	15,960
201802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	15,960
201803	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	15,960
201804	-	-	-	2,958,647	-	-	-	-	-	-	-	-	-	-	-	-	15,960	2,974,608
201805	-	-	-	3,001,078	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,017,039
201806	-	-	-	3,025,289	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,041,250
201807	-	-	-	3,075,342	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,091,303
201808	-	-	-	3,110,735	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,126,695
201809	-	-	-	3,124,479	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,140,440
201810	-	-	-	3,138,371	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,154,331
201811	-	-	43,907,080	3,198,636	-	-	-	-	-	-	-	-	-	-	-	10,996,024	15,960	58,117,701
201812	-	-	43,953,373	3,206,089	-	-	-	-	-	-	-	-	-	-	-	11,192,993	15,960	58,368,415
201901	-	-	44,707,015	3,209,400	-	-	-	-	-	-	-	-	-	-	-	11,221,347	15,960	59,153,723
201902	-	-	45,206,368	3,209,346	-	-	-	-	-	-	-	-	-	-	-	11,378,365	15,960	59,810,039
201903	-	-	45,977,206	3,209,346	148	-	-	-	-	-	5,427,139	-	-	48,143,259	-	11,435,527	15,960	114,208,587
201904	-	-	46,309,642	3,209,346	148	-	-	-	-	-	5,472,022	8,985,508	-	49,435,157	-	11,270,275	15,960	124,698,058
201905	-	-	46,201,251	3,209,346	148	-	-	-	-	-	5,506,137	9,129,387	-	50,165,779	-	11,361,698	15,960	125,589,706
201906	-	-	46,249,852	3,209,346	148	-	-	-	-	-	5,639,786	9,327,391	-	50,845,637	-	11,568,520	15,960	126,856,640
201907	-	-	46,458,186	3,209,346	148	-	-	-	-	-	5,646,454	9,396,738	-	51,348,818	-	11,532,972	15,960	127,608,624
201908	(153,356)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,699,778	9,548,292	-	51,528,893	-	11,763,598	15,960	128,070,846
201909	(100,553)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,843,890	9,797,184	-	51,963,946	-	11,920,039	15,960	129,108,148
201910	(100,553)	-	46,465,023	3,209,346	148	-	-	-	-	-	5,828,894	10,061,859	-	52,288,417	-	11,963,842	15,960	129,732,937
201911	(100,553)	-	46,456,551	3,209,346	148	-	-	-	-	-	5,908,257	9,799,788	-	52,209,195	-	12,185,076	15,960	129,683,770
201912	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,823,981	-	52,500,827	-	12,201,762	15,960	130,019,286
202001	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,830,650	-	52,782,085	-	12,198,754	15,960	130,304,205
202002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Tax Basis for Bonus Depreciation ADIT

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project																		
Description																		
Bonus Depr Eligibl	YES	NO	YES	YES	YES	NO	NO	No	No	NO	YES	YES	NO	YES	NO	YES	YES	
Initial In Service `	2018	2018	2018	2018	2018	2018	2018	2018	2018	2019	2019	2019	2019	2019	2019	2018	2018	
Bonus Depr %	50%		50%	50%	50%						40%	40%		40%		50%	50%	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201803	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201804	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201805	-	-	-	2,958,647	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201806	-	-	-	3,001,078	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201807	-	-	-	3,025,289	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201808	-	-	-	3,075,342	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201809	-	-	-	3,110,735	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201810	-	-	-	3,124,479	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201811	-	-	-	3,138,371	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201812	-	-	43,907,080	3,198,636	-	-	-	-	-	-	-	-	-	-	-	10,996,024	15,960	
201901	-	-	43,953,373	3,206,089	-	-	-	-	-	-	-	-	-	-	-	11,192,993	15,960	
201902	-	-	44,707,015	3,209,400	-	-	-	-	-	-	-	-	-	-	-	11,221,347	15,960	
201903	-	-	45,206,368	3,209,346	-	-	-	-	-	-	-	-	-	-	-	11,378,365	15,960	
201904	-	-	45,977,206	3,209,346	148	-	-	-	-	-	5,427,139	-	-	48,143,259	-	11,435,527	15,960	
201905	-	-	46,309,642	3,209,346	148	-	-	-	-	-	5,472,022	8,985,508	-	49,435,157	-	11,270,275	15,960	
201906	-	-	46,201,251	3,209,346	148	-	-	-	-	-	5,506,137	9,129,387	-	50,165,779	-	11,361,698	15,960	
201907	-	-	46,249,852	3,209,346	148	-	-	-	-	-	5,639,786	9,327,391	-	50,845,637	-	11,568,520	15,960	
201908	-	-	46,458,186	3,209,346	148	-	-	-	-	-	5,646,454	9,396,738	-	51,348,818	-	11,532,972	15,960	
201909	(153,356)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,699,778	9,548,292	-	51,528,893	-	11,763,598	15,960	
201910	(100,553)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,843,890	9,797,184	-	51,963,946	-	11,920,039	15,960	
201911	(100,553)	-	46,465,023	3,209,346	148	-	-	-	-	-	5,828,894	10,061,859	-	52,288,417	-	11,963,842	15,960	
201912	(100,553)	-	46,456,551	3,209,346	148	-	-	-	-	-	5,908,257	9,799,788	-	52,209,195	-	12,185,076	15,960	
202001	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,823,981	-	52,500,827	-	12,201,762	15,960	
202002	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,830,650	-	52,782,085	-	12,198,754	15,960	

Accumulated Deferred Income taxes

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project																		
Description																		
Tax Rate	23.1693%																	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201803	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201804	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201805	-	-	-	(685,498)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(689,196)
201806	-	-	-	(695,329)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(699,027)
201807	-	-	-	(700,938)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(704,636)
201808	-	-	-	(712,535)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(716,233)
201809	-	-	-	(720,735)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(724,433)
201810	-	-	-	(723,920)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(727,618)
201811	-	-	-	(727,139)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(730,836)
201812	-	-	(10,172,963)	(741,102)	-	-	-	-	-	-	-	-	-	-	-	(2,547,702)	(3,698)	(13,465,465)
201901	-	-	(10,183,689)	(742,828)	-	-	-	-	-	-	-	-	-	-	-	(2,593,338)	(3,698)	(13,523,554)
201902	-	-	(10,358,303)	(743,596)	-	-	-	-	-	-	-	-	-	-	-	(2,599,908)	(3,698)	(13,705,504)
201903	-	-	(10,473,999)	(743,583)	-	-	-	-	-	-	-	-	-	-	-	(2,636,287)	(3,698)	(13,857,568)
201904	-	-	(10,652,597)	(743,583)	(34)	-	-	-	-	-	(1,257,430)	-	-	(11,154,456)	-	(2,649,532)	(3,698)	(26,461,331)
201905	-	-	(10,729,620)	(743,583)	(34)	-	-	-	-	-	(1,267,829)	(2,081,879)	-	(11,453,780)	-	(2,611,244)	(3,698)	(28,891,668)
201906	-	-	(10,704,507)	(743,583)	(34)	-	-	-	-	-	(1,275,733)	(2,115,215)	-	(11,623,060)	-	(2,632,426)	(3,698)	(29,098,256)
201907	-	-	(10,715,767)	(743,583)	(34)	-	-	-	-	-	(1,306,699)	(2,161,091)	-	(11,780,578)	-	(2,680,345)	(3,698)	(29,391,796)
201908	-	-	(10,764,037)	(743,583)	(34)	-	-	-	-	-	(1,308,244)	(2,177,158)	-	(11,897,162)	-	(2,672,109)	(3,698)	(29,566,025)
201909	35,532	-	(10,764,037)	(743,583)	(34)	-	-	-	-	-	(1,320,599)	(2,212,272)	-	(11,938,884)	-	(2,725,543)	(3,698)	(29,673,119)
201910	23,297	-	(10,764,037)	(743,583)	(34)	-	-	-	-	-	(1,353,989)	(2,269,939)	-	(12,039,683)	-	(2,761,790)	(3,698)	(29,913,455)
201911	23,297	-	(10,765,621)	(743,583)	(34)	-	-	-	-	-	(1,350,514)	(2,331,262)	-	(12,114,861)	-	(2,771,939)	(3,698)	(30,058,214)
201912	23,297	-	(10,763,658)	(743,583)	(34)	-	-	-	-	-	(1,368,902)	(2,270,542)	-	(12,096,505)	-	(2,823,197)	(3,698)	(30,046,822)
202001	23,297	-	(10,763,648)	(743,583)	(34)	-	-	-	-	-	(1,369,608)	(2,276,148)	-	(12,164,074)	-	(2,827,063)	(3,698)	(30,124,559)
202002	23,297	-	(10,763,648)	(743,583)	(34)	-	-	-	-	-	(1,369,608)	(2,277,693)	-	(12,229,240)	-	(2,826,366)	(3,698)	(30,190,573)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1200
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma annualizes test period operation and maintenance expenses excluding fuel, purchased power, and labor and benefit costs to reflect the change in unit costs that occurred during the test period.

The impact to operation and maintenance expenses is determined as follows:

First, calculate total operation and maintenance expense excluding fuel and purchased power but including labor that needs to be adjusted. This calculation is done by starting with per book operation and maintenance expense, excluding fuel and purchased power, and subtracting all pro-forma adjustments that impacted this amount.

Second, subtract net electric operation and maintenance salaries and wages from operation and maintenance expenses including labor.

Third, subtract fringe benefits from operation and maintenance expenses including labor. Fringe benefits are calculated by multiplying net electric operation and maintenance salaries and wages by the fringe benefits contribution rate.

Finally, the impact to operation and maintenance expense is calculated by multiplying total non-labor operation and maintenance expenses by the average inflation rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update

Updated NC-1201 to remove CertainTeed cost adjustment in accordance with Commission order under Docket No. E-2, Sub 1204

November update

Updated NC-1203, NC-1204 and NC-1205 for most up to date index values

December update

Updated index values on NC-1203, NC-1204 and NC-1205 and for impacts flowing from other adjustment

January update

Updated index values on NC-1203, NC-1204 and NC-1205 and for impacts flowing from other adjustment

February update

Updated for impacts flowing from other adjustments; No revision made to index values as updates were n available as of Supplemental filing date

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1200
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-1201	1,319	1,311	8
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1201	(306)	(304)	(2)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L6 through L15	1,013	1,007	6
18					
19	Operating income	L4 - L17	$ (1,013)	$ (1,007)	$ (6)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1201
Supplemental
February Update

Line No.	Description	Supplemental Total System	Supplemental NC Retail Allocation	Supplemental Total NC Retail
1				
2				
3	O&M (excluding fuel and purchased power)	$ 1,546,719 [1]		$ 1,050,819 [1]
4				
5	Less: reagents expense and proceeds from sale of by-products	(102,730) [2]		(62,778) [2]
6	Less: costs recovered through non-fuel riders	(192,911) [3]		(136,143) [3]
7	Less: Ernst & Young outside tax services contract	(592) [4]	66.2120% [20]	(392) [4]
8	Less: nuclear refueling outage costs	(40,225) [5]		(40,225) [5]
9	Less: amortization of prior rate case costs	(1,012) [6]		(1,012) [6]
10	Less: aviation expenses	(1,579) [7]	66.2120% [20]	(1,045) [7]
11	Less: expiring amortizations	(1,673) [8]		(1,673) [8]
12	Less: merger related costs	(5,969) [9]		(4,039) [9]
13	Less: severance and retention costs	(52,890) [10]	66.2120% [20]	(35,020) [10]
14	Less: vegetation management expenses - distribution	(36,515) [11]	83.9171% [18]	(30,643) [11]
15	Less: vegetation management expenses - transmission	(8,143) [11]	59.6699% [19]	(4,859) [11]
16	Less: NCUC regulatory fee	(4,889) [12]		(4,889) [12]
17	Less: CertainTeed payment obligation	- [13]	61.1093% [21]	- [13]
18				
19	Total O&M to be adjusted including labor (Sum L3 through L17)	$ 1,097,593		$ 728,104
20				
21	Net electric O&M salaries and wages	$ 649,874 [14]		
22	Fringe benefits contribution rate	20.50% [15]		
23	Fringe benefits (L21 x L22)	$ 133,210		
24				
25	Less: net electric O&M salaries & wages and fringe benefits (L21 + L23)	$ 783,084	66.2120% [20]	$ 518,496
26				
27	Total non-labor O&M to be adjusted (L19 - L25)	$ 314,509		$ 209,608
28	Average inflation rate	0.63% [16]		0.63% [15]
29	Impact to O&M - non-labor O&M adjustment to reflect end of period costs (L27 x L28)	$ 1,979		$ 1,319
30				
31	Statutory tax rate	23.1693% [17]		23.1693% [16]
32	Impact to income taxes (-L29 x L31)	$ (459)		$ (306)
33	Impact to operating income (-L29 - L32)	$ (1,521)		$ (1,013)

[1] Smith Exhibit 1, Other O&M, Page 1, Line 4, Columns 1 and 2
[2] NC-0201 - Update fuel costs to approved rate
[3] NC-0601 - Eliminate costs recovered through non-fuel riders, Line 23
[4] NC-1311 - Adjustment to annualized Ernst & Young outside tax services contract, Line 2
[5] NC-1501 - Levelize nuclear refueling outage costs, Line 21
[6] E-1 Item 45A
[7] NC-1702 - Adjust aviation expenses, Line 5
[8] NC-1801 - Adjust for approved regulatory assets and liabilities, Line 3
[9] NC-1901 - Adjust for merger related costs, Line 4
[10] NC-2001 - Amortize severance costs - Actuals, Line 4
[11] NC-2702 - Adjust for vegetation management - distribution and transmission, Lines 11 and 23
[12] E-1 Item 45A
[13] NC-3301, Line 10
[14] NC-1301, Line 14
[15] NC-1301, Line 34
[16] NC-1203 - Average of Consumer Price Index and Producer Price Index, Line 19
[17] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[18] NC Retail Allocation Factor - RB_PLT_O_DI_OH_LN
[19] NC Retail Allocation Factor - DTALL
[20] NC Retail Allocation Factor - LAB
[21] NC Retail Allocation Factor - E1ALL

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1202
Supplemental
February Update

Average of Consumer Price Index and Producer Price Index

Line No.	Period	CPI [1] (a)	PPI [2] Finished goods less food & energy (b)	PPI [3] Processed materials less food & energy (c)	PPI Average (d)= Average of (b) and (c)
1	December 2017	246.5	200.6	196.3	
2	January 2018	247.9	200.9	197.2	
3	February 2018	249.0	201.3	198.3	
4	March 2018	249.6	201.8	199.3	
5	April 2018	250.5	202.3	199.8	
6	May 2018	251.6	202.7	201.3	
7	June 2018	252.0	203.1	202.3	
8	July 2018	252.0	203.7	203.0	
9	August 2018	252.1	204.2	203.7	
10	September 2018	252.4	204.6	204.5	
11	October 2018	252.9	205.1	204.8	
12	November 2018	252.0	205.6	204.2	
13	December 2018	251.2	205.8	203.1	
14					
15	13 month average	250.8	203.2	201.4	
16					
17	Increase from average to year end (L13 - L15)	0.5	2.6	1.7	
18	% increase from average to year end (L17 / L15)	0.19%	1.28%	0.86%	1.07%
19	Average inflation rate (Average, Line 18, Col. (a) and Col. (d))	0.63%			

[1] NC-1203 - Consumer Price Index - All Items
[2] NC-1204 - Producer Price Index - Commodities - Finished goods less food and energy
[3] NC-1205 - Producer Price Index - Commodities - Processed materials less food and energy

Note: Totals may not foot due to rounding.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1203
Supplemental
February Update

Consumer Price Index - All Urban Consumers
Original Data Value

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	211.1	212.2	212.7	213.2	213.9	215.7	215.4	215.8	216.0	216.2	216.3	215.9	214.5
2010	216.7	216.7	217.6	218.0	218.2	218.0	218.0	218.3	218.4	218.7	218.8	219.2	218.1
2011	220.2	221.3	223.5	224.9	226.0	225.7	225.9	226.5	226.9	226.4	226.2	225.7	224.9
2012	226.7	227.7	229.4	230.1	229.8	229.5	229.1	230.4	231.4	231.3	230.2	229.6	229.6
2013	230.3	232.2	232.8	232.5	232.9	233.5	233.6	233.9	234.1	233.5	233.1	233.0	233.0
2014	233.9	234.8	236.3	237.1	237.9	238.3	238.3	237.9	238.0	237.4	236.2	234.8	236.7
2015	233.7	234.7	236.1	236.6	237.8	238.6	238.7	238.3	237.9	237.8	237.3	236.5	237.0
2016	236.9	237.1	238.1	239.3	240.2	241.0	240.6	240.8	241.4	241.7	241.4	241.4	240.0
2017	242.8	243.6	243.8	244.5	244.7	245.0	244.8	245.5	246.8	246.7	246.7	246.5	245.1
2018	247.9	249.0	249.6	250.5	251.6	252.0	252.0	252.1	252.4	252.9	252.0	251.2	251.1
2019	251.7	252.8	254.2	255.5	256.1	256.1	256.6	256.6	256.8	257.3	257.2	257.0	255.7
2020	258.0												258.0

Source: Bureau of Labor Statistics

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1204
Supplemental
February Update

Producer Price Index-Commodities
Original Data Value

Series Id: WPSFD4131
Seasonally Adjusted
Group: Final demand
Item: Finished goods less foods and energy
Base Date: 198200
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	170.8	170.9	171.2	171.3	171.2	171.8	171.4	171.8	171.6	171.5	172.1	172.1	171.5
2010	172.5	172.6	172.9	172.9	173.4	173.6	173.7	173.9	174.3	174.3	174.3	174.6	173.6
2011	175.3	175.7	176.2	176.8	177.0	177.6	178.2	178.5	179.0	179.4	179.6	180.0	177.8
2012	180.7	181.0	181.3	181.6	181.8	182.1	182.9	183.2	183.2	183.3	183.7	183.7	182.4
2013	183.9	184.2	184.4	184.6	184.8	185.0	185.2	185.3	185.4	185.6	185.9	186.7	185.1
2014	187.5	187.7	187.7	187.9	188.2	188.5	188.7	189.0	189.2	189.7	189.7	189.8	188.6
2015	190.7	191.3	191.5	191.6	191.8	192.7	193.0	193.0	193.2	193.0	193.1	193.4	192.4
2016	193.9	194.2	194.3	194.6	194.9	195.4	195.4	195.7	195.8	196.1	196.3	196.7	195.3
2017	197.1	197.4	197.8	198.5	198.6	198.8	198.9	199.2	199.2	200.0	200.5	200.6	198.9
2018	200.9	201.3	201.8	202.3	202.7	203.1	203.7	204.2	204.6	205.1	205.6	205.8	203.4
2019	206.6	206.9	207.2	207.5	207.8	207.7	208.1	208.2	208.4	208.4	208.7	209.0	207.9
2020	209.1												209.1

Source: Bureau of Labor Statistics

Note: Items highlighted green above are preliminary. All indexes are subject to revision four months after original publication.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1205
Supplemental
February Update

Producer Price Index-Commodities
Original Data Value

Series Id: WPSID69115
Seasonally Adjusted
Group: Intermediate demand by commodity type
Item: Processed materials less foods and
Base Date: 198200
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	174.8	173.5	172.7	171.8	171.4	171.8	172.2	173.2	174.2	174.5	174.9	175.9	173.4
2010	177.0	178.4	179.6	181.4	181.8	180.9	180.2	180.5	180.9	182.0	183.1	184.1	180.8
2011	186.6	188.8	190.2	192.4	193.5	193.7	194.2	194.2	194.2	193.0	192.3	191.3	192.0
2012	192.0	193.2	194.5	194.7	194.1	191.9	191.2	191.3	192.0	192.2	192.1	192.6	192.7
2013	193.7	194.7	194.4	193.9	193.6	193.5	193.3	193.7	193.7	193.6	193.6	194.0	193.8
2014	194.6	195.2	194.8	195.1	195.0	195.1	195.9	196.3	196.3	195.8	194.9	193.9	195.2
2015	191.8	191.1	190.5	190.1	190.1	190.2	190.0	189.1	188.1	187.7	187.1	186.6	189.4
2016	185.8	185.2	185.1	185.7	186.2	186.6	186.9	187.4	187.7	188.0	188.7	189.4	186.9
2017	190.0	191.3	192.1	192.9	192.8	193.1	192.9	193.5	194.2	195.0	196.0	196.3	193.3
2018	197.2	198.3	199.3	199.8	201.3	202.3	203.0	203.7	204.5	204.8	204.2	203.1	201.8
2019	203.1	202.7	202.4	202.2	201.7	201.0	200.7	200.0	199.7	199.9	199.4	199.1	201.0
2020	199.6												199.6

Source: Bureau of Labor Statistics

Note: Items highlighted green above are preliminary. All indexes are subject to revision four months after original publication.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1300
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts operation and maintenance expense, general taxes and income taxes to normalize operation and maintenance labor costs.

The impact to operation and maintenance expense is determined as follows:

1. The salaries and wages booked during the test period are subtracted from salaries and wages at June 30, 2019 per Human Resources.

2. The percentage of electric operation and maintenance expense to apply to the salaries and wages adjustment is calculated as follows: total operation and maintenance labor per Form 1, Page 354 is divided by total salaries and wages excluding other work in progress and allocation of clearing accounts per Form 1, Page 355. The adjustment calculated in Step 1 i multiplied by this percentage.

3. The impact to related fringe benefit costs is calculated by multiplying the salaries and wage adjustment calculated in Step 1 by the fringe benefits contribution rate. The fringe benefits contribution rate is calculated by dividing account 926 - employee pensions and benefits booked during the test period by total operation and maintenance labor per Form 1, Page 354.

4. The impact to operation and maintenance expense also reflects an adjustment to restate variable short and long term pay booked during the test period to target.

The impact to general taxes reflects the change in the FICA tax base. To adjust general taxes, the salaries and wages adjustment calculated in Step 1 is multiplied by the percentage of wages subject to OASDI by the OASDI tax rate for employers. Next, the adjustment due to Medicare tax is calculated by multiplying the salaries and wages adjustment calculated in Step 1 by the Medicare tax rate.

The impact to income taxes was determined by multiplying taxable income by the statutory tax rate.

October Update

NC-1304, and NC1305 have all been updated for 12 months ended October 2019

November Update

NC-1304, and NC1305 have all been updated for 12 months ended November 2019

December Update

NC-1304, and NC1305 have all been updated for 12 months ended December 2019
NC-1311 E&Y Fees have been updated for 2019 Actuals

January Update

NC-1304, and NC1305 have all been updated through January 2020

February Update

NC-1304, and NC1305 have all been updated through February 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1300
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-1301	(19,794)	(18,512)	(1,282)
11	Depreciation and amortization		-	-	-
12	General taxes	NC-1301	(1,162)	(1,089)	(72)
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1301	4,855	4,542	314
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(16,100)	(15,060)	(1,040)
18					
19	Operating income	L4 - L17	$ 16,100	$ 15,060	$ 1,040
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Labor Per Books		As of 2/29/2020 HR Salaries		Pro Forma HR salaries	
1							
2	Salaries and Wages by Payroll Company						
3	Duke Energy Carolinas - salaries and wages - charged to Duke Energy Progress	$ 85,883	[1]	$ 81,894	[2]	$ (3,990)	
4	Service Company DEBS - salaries and wages - charged to Duke Energy Progress	133,040	[1]	128,906	[2]	(4,134)	
5	Duke Energy Progress - salaries and wages	425,470	[1]	399,697	[2]	(25,774)	
6	Total salaries and wages (Sum L3 through L5)	$ 644,394		$ 610,496		$ (33,897)	
7							
8	Calculation of Electric O&M % to Apply to Salaries & Wages Adjustment						
9	Total salaries and wages (Form 1, Page 355, Line 96, Col (d))	$ 878,621	[4]				
10	Less: other work in progress (Form 1, Page 355, Line 78, Col (b))	4,751	[4]				
11	Less: allocation of payroll charged for clearing accounts (Form 1, Page 355, Line 96, Col (c))	18,495	[4]				
12	Total salaries and wages - excluding other WIP and allocation of clearing accounts (L9 - L10 - L11	$ 855,375					
13							
14	Total operating and maintenance (Form 1, Page 354, Line 28, Col (b))	$ 649,874	[4]				
15							
16	Percent of incurred costs charged to electric expense (L14 / L12)	75.98%				75.98%	
17	Net electric O&M salaries and wages to adjust (L6 x L16)					$ (25,754)	
18							
19	Adjustment to General Taxes - FICA						
20	Net electric O&M salaries and wages to adjust (L17)					$ (25,754)	
21	Percentage of wages subject to OASDI					86.49%	[5]
22	Electric wage adjustment subject to OASDI tax (L20 x L21)					$ (22,273)	
23	OASDI tax rate (employers)					6.20%	[6]
24	Adjustment due to wage adjustment (before Medicare rate) (L22 x L23)					$ (1,381)	
25							
26	Net electric O&M salaries and wages to adjust (L17)					$ (25,754)	
27	Medicare tax rate					1.45%	[6]
28	Adjustment due to Medicare tax (L26 x L27)					$ (373)	
29	Impact to general taxes (L24 + L28)					$ (1,754)	
30							
31	Calculation of Fringe Benefits Contribution Rate						
32	Account 926 - employee pensions and benefits - 12 Months Ended December 31, 2018	$ 133,210	[7]				
33	Total operating and maintenance (Form 1, Page 354, Line 28, Col (b)) (L14)	649,874					
34	Fringe benefits contribution rate (L32 / L33)	20.50%					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description		Total System	NC Retail Allocation	Total NC Retail
35					
36	Calculation of O&M (Including Fringe Benefits & Variable Pay) and Income Tax				
37	Net electric O&M salaries and wages to adjust (L17)		$ (25,754)		
38	Fringe benefits contribution rate (L34)		20.50%		
39	Fringe benefits adjustment (L37 x L38)		$ (5,279)		
40					
41	Adjustment to restate variable short and long term pay at target	NC-1310	$ (35) [8]		
42	Adjustment to Annualize E&Y Tax Service Contract	NC-1311	$ 1,173		
43					
44	Impact to O&M (L37 + L39 + L41)		$ (29,895)	66.2120% [9]	$ (19,794)
45					
46	Impact to general taxes (L29)		$ (1,754)	66.2120% [9]	$ (1,162)
47					
48	Taxable income (-L44 - L46)		$ 31,649		$ 20,955
49	Statutory tax rate		23.1693% [10]		23.1693% [10]
50	Impact to income taxes (L48 x L49)		$ 7,333		$ 4,855
51					
52	Impact to operating income (L48 - L50)		$ 24,316		$ 16,100

[1] NC-1302 - Salaries and Wages by Payroll Company for Duke Energy Progress - 12 Months Ended Dec 31, 2018
[2] NC-1304 - Annual Salary Information by Payroll Company for Duke Energy Progress - Dec 31, 2019
[4] NC-1306 - Distribution of Salaries and Wages, 12 Months Ended December 31, 2018 (Form 1, Page 354-355)
[5] NC-1307 - Quarterly Federal Tax Summary Report
[6] NC-1308 - OASDI and SSI Program Rates & Limits - 2019
[7] NC-1309 - Duke Energy Progress - (926) Employee Pensions and Benefits - 12 Months Ended December 31, 2018
[8] NC-1310 - Variable Short and Long Term Pay for Duke Energy Progress
[9] NC Retail Allocation Factor - LAB
[10] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1302
Supplemental
February Update

Salaries and Wages by Payroll Company for Duke Energy Progress - 12 Months Ended December 31, 2018

Line No.	Payroll Company	Resource Category	Capital	O&M	Total	
1						
2	Duke Energy Carolinas (Payroll Company 100) - charged to DE Progress	Direct Labor	$ 14,986,733	$ 49,780,040	$ 64,766,773	75.41%
3	Duke Energy Carolinas (Payroll Company 100) - charged to DE Progress	Allocated Labor	2,634,654	18,481,953	21,116,607	24.59%
4	Subtotal		$ 17,621,387	$ 68,261,993	$ 85,883,380	100.00%
5						
6	Service Company (Payroll Company 110) - charged to DE Progress	Direct Labor	$ 35,368,447	$ 78,383,690	$ 113,752,137	85.50%
7	Service Company (Payroll Company 110) - charged to DE Progress	Allocated Labor	6,659,597	12,628,346	19,287,943	14.50%
8	Subtotal		$ 42,028,044	$ 91,012,036	$ 133,040,080	100.00%
9						
10	Duke Energy Progress (Payroll Company 801)	Direct Labor	$ 102,240,101	$ 252,616,285	$ 354,856,386	83.40%
11	Duke Energy Progress (Payroll Company 801)	Allocated Labor	20,004,454	50,609,387	70,613,841	16.60%
12	Subtotal		$ 122,244,555	$ 303,225,672	$ 425,470,227	100.00%
13						
14	Total		$ 181,893,987	$ 462,499,701	$ 644,393,688	

Note: Totals may not foot due to rounding
Source: Duke Energy Progress General Accounting and Reporting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1303
Supplemental
February Update

[BLANK PAGE]

There are no joint owner reimbursements to consider.

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1304
Supplemental
February Update

Annual Salary Information by Payroll Company for Duke Energy Progress - February 29, 2020

Line No.	Payroll Company	Grand Total	
1			
2	Duke Energy Carolinas (Payroll Company 100)	$ 801,708,765	[2]
3	Duke Energy Carolinas % of labor charged to Duke Energy Progress	10.21%	[1]
4	Duke Energy Carolinas labor charged to Duke Energy Progress (L2 x L3)	$ 81,893,639	
5			
6	Service Company (Payroll Company 110)	$ 745,091,492	[2]
7	Service Company % of labor charged to Duke Energy Progress	17.30%	[1]
8	Service Company labor charged to Duke Energy Progress (L6 x L7)	$ 128,906,001	
9			
10	Duke Energy Progress (Payroll Company 801)	$ 435,427,549	[2]
11	Duke Energy Progress % of labor charged to Duke Energy Progress	91.79%	[1]
12	Duke Energy Progress labor charged to Duke Energy Progress (L10 x L11)	$ 399,696,637	
13			
14	Total - sum of annual salaries (L4 + L8 + L12)	$ 610,496,278	

[1] NC-1305 - Labor Allocations by Business Unit Group - 12 Months Ended February 29, 2020
[2] Information provided by Duke Energy Human Resources Operations

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1305
Supplemental
February Update

Labor Allocations by Business Unit Group - 12 Months Ended February 29, 2020
Base Labor Resource Types Included: 11000, 11002, 18000, 18001, 18005

Line No.	Resp Center Level 2 Node Name LVL	BU Group	Monetary Amount JD	Percentage
1				
2	100_DUKE_POWER_CONSO	1. DE Carolinas	$ 667,603,184	83.16%
3	100_DUKE_POWER_CONSO	2. DE Progress	81,999,857	10.21%
4	100_DUKE_POWER_CONSO	3. DEBS	731,061	0.09%
5	100_DUKE_POWER_CONSO	4. Other	52,414,494	6.53%
6	100_DUKE_POWER_CONSO		$ 802,748,596	100.00%
7				
8	110_SERVICE_COMPANY	1. DE Carolinas	$ 190,415,036	25.03%
9	110_SERVICE_COMPANY	2. DE Progress	131,622,269	17.30%
10	110_SERVICE_COMPANY	3. DEBS	48,716,346	6.40%
11	110_SERVICE_COMPANY	4. Other	390,038,178	51.27%
12	110_SERVICE_COMPANY		$ 760,791,829	100.00%
13				
14	801_DE_PROGRESS	1. DE Carolinas	$ 28,685,145	6.39%
15	801_DE_PROGRESS	2. DE Progress	412,040,170	91.79%
16	801_DE_PROGRESS	3. DEBS	119,766	0.03%
17	801_DE_PROGRESS	4. Other	8,029,452	1.79%
18	801_DE_PROGRESS		$ 448,874,533	100.00%
19				
20	Total		$ 2,012,414,959	

Source: Duke Energy Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1306
Supplemental
February Update
Page 1 of 2

Page 354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	221,082,961		
4	Transmission	8,332,490		
5	Regional Market			
6	Distribution	20,838,503		
7	Customer Accounts	21,023,608		
8	Customer Service and Informational	2,244,420		
9	Sales	4,977,267		
10	Administrative and General	144,784,387		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	423,283,636		
12	Maintenance			
13	Production	166,244,358		
14	Transmission	10,965,389		
15	Regional Market			
16	Distribution	49,241,516		
17	Administrative and General	139,214		
18	TOTAL Maintenance (Total of lines 13 thru 17)	226,590,477		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	387,327,319		
21	Transmission (Enter Total of lines 4 and 14)	19,297,879		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	70,080,019		
24	Customer Accounts (Transcribe from line 7)	21,023,608		
25	Customer Service and Informational (Transcribe from line 8)	2,244,420		
26	Sales (Transcribe from line 9)	4,977,267		
27	Administrative and General (Enter Total of lines 10 and 17)	144,923,601		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	649,874,113	3,710,561	653,584,674
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1306
Supplemental
February Update

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	649,874,113	3,710,561	653,584,674
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	163,441,091	14,784,255	178,225,346
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	163,441,091	14,784,255	178,225,346
72	Plant Removal (By Utility Departments)			
73	Electric Plant	30,303,443		30,303,443
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	30,303,443		30,303,443
77	Other Accounts (Specify, provide details in footnote):			
78	Non-Regulated Products and Services	4,750,987		4,750,987
79	Other Work in Progress	4,471,750		4,471,750
80	Other Accounts	7,284,796		7,284,796
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	16,507,533		16,507,533
96	TOTAL SALARIES AND WAGES	860,126,180	18,494,816	878,620,996

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1307
Supplemental
February Update
Page 1 of 2
Source: Duke Energy HR Operations

Quarterly Federal Tax Summary Report (Report ID: TAX010FD) - Summary

Line No.	Description							12 Months Ended Dec 31, 2018	
1		(a)		(b)		(c)		(d)	
2	Duke Energy Carolinas								
3	100 Duke Energy Carolinas, LLC OASDI [ER] YTD Gross Wages							$ 1,087,229,757	[1]
4	100 Duke Energy Carolinas, LLC OASDI [ER] YTD Taxable Wages							938,515,849	[1]
5	Percentage Total (L4 / L3)							86.32%	
6									
7	Duke Energy Business Services								
8	110 Duke Energy Business Services, LLC OASDI [ER] YTD Gross Wages							$ 950,101,600	[2]
9	110 Duke Energy Business Services LLC OASDI [ER] YTD Taxable Wages							778,374,460	[2]
10	Percentage Total (L9 / L8)							81.93%	
11									
12	Duke Energy Progress								
13	801 Duke Energy Progress, LLC OASDI [ER] YTD Gross Wages							$ 613,149,643	[3]
14	801 Duke Energy Progress, LLC OASDI [ER] YTD Taxable Wages							539,237,877	[3]
15	Percentage Total (L14 / L13)							87.95%	
16									
17	Calculation of Percentage of Wages Subject to OASDI								
18	For 12 Months Ended December 31, 2018								
19	Duke Energy Carolinas	$ 85,883,380	[4]	13.33%	[5]	86.32%	[8]	11.50%	[11]
20	Duke Energy Business Services	133,040,080	[4]	20.65%	[6]	81.93%	[9]	16.91%	[11]
21	Duke Energy Progress	425,470,227	[4]	66.03%	[7]	87.95%	[10]	58.07%	[11]
22	Total (Sum L19 through L21)	$ 644,393,688		100.00%				86.49%	

[1] NC-1307, Quarterly Federal Tax Summary Report - 4th Quarter 2018, Company: 100
[2] NC-1307, Quarterly Federal Tax Summary Report - 4th Quarter 2018, Company: 110
[3] NC-1307, Quarterly Federal Tax Summary Report - 4th Quarter 2018, Company: 801
[4] NC-1302 - Salaries and Wages by Payroll Company for Duke Energy Progress - 12 Months Ended December 31, 2018
[5] Column (a), Line 19 divided by Line 22
[6] Column (a), Line 20 divided by Line 22
[7] Column (a), Line 21 divided by Line 22
[8] Column (d), Line 5
[9] Column (d), Line 10
[10] Column (d), Line 15
[11] Column (b) multiplied by Column (c)

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

Quarterly Federal Tax Summary Report

Company	Quarter	Tax Authorit	EIN	Tax	QTD Withheld	QTD Taxable Wages	QTD Gross Wages	YTD Tax Withheld	YTD Taxable Wages	YTD Gross Wages
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Additional Medicare Tax	104,974.70	11,663,853.10	11,663,853.10	282,793.95	31,421,542.88	31,421,542.88
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Federal Withholding	28,536,104.44	217,903,543.03	247,576,721.94	128,668,020.04	951,227,720.66	1,085,375,221.61
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	FUI (ER)	7,814.72	1,302,349.11	247,394,057.93	425,889.10	70,981,398.12	1,085,502,960.39
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Medicare (ER)	3,427,570.58	236,384,057.64	247,916,479.73	15,075,010.04	1,039,655,751.63	1,087,229,756.77
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Medicare	3,427,602.66	236,384,552.37	247,936,628.56	15,075,015.30	1,039,656,246.36	1,087,229,699.23
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	OASDI (ER)	11,044,837.60	178,142,417.46	247,916,479.73	58,187,990.70	938,515,848.91	1,087,229,756.77
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	OASDI	11,044,869.55	178,142,912.19	246,965,125.67	58,188,013.61	938,516,343.64	1,084,491,252.86
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Additional Medicare Tax	191,753.93	21,305,989.49	21,305,989.49	651,529.46	72,392,154.27	72,392,154.27
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Federal Withholding	24,460,997.11	182,836,171.89	207,390,610.00	122,163,890.03	835,162,767.20	947,110,242.18
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	FUI (ER)	8,159.62	1,359,946.18	207,624,794.33	375,114.04	62,519,025.03	948,631,033.96
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Medicare (ER)	2,872,403.28	198,096,763.28	208,008,186.10	13,197,524.85	910,174,139.03	950,101,596.15
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Medicare	2,872,409.66	198,097,158.67	208,059,234.06	13,197,530.70	910,174,542.29	950,064,243.15
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	OASDI (ER)	9,085,708.46	146,543,683.20	208,008,190.06	48,259,216.85	778,374,459.54	950,101,600.11
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	OASDI	9,085,473.10	146,543,922.04	204,973,055.80	48,259,232.15	778,374,706.55	935,817,798.97
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Additional Medicare Tax	39,261.27	4,362,352.52	4,369,223.21	101,191.04	11,243,439.39	11,250,310.08
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Federal Withholding	15,957,342.77	123,629,596.26	140,175,939.25	71,856,843.21	537,401,484.37	612,187,559.85
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	FUI (ER)	4,006.42	667,734.28	140,002,620.05	239,162.45	39,860,404.92	612,429,759.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Medicare (ER)	1,940,423.35	133,822,341.37	140,181,009.46	8,506,298.22	586,641,267.42	613,149,642.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Medicare	1,940,423.45	133,822,341.37	140,224,083.49	8,506,298.21	586,641,267.42	613,149,642.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	OASDI (ER)	6,427,921.91	103,676,152.17	140,181,009.46	33,432,748.73	539,237,876.69	613,149,642.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	OASDI	6,428,101.62	103,679,042.20	139,922,162.99	33,432,748.72	539,237,876.69	612,329,162.31

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1308
Supplemental
February Update

OASDI and SSI Program Rates & Limits 2019

Old-Age, Survivors, and Disability Insurance (OASDI)

Tax Rates (percent)	
Social Security (Old-Age, Survivors, and Disability Insurance)	
Employers and Employees, each [a]	6.20
Medicare (Hospital Insurance)	
Employers and Employees, each [a,b]	1.45
Maximum Taxable Earnings (dollars)	
Social Security	132,900
Medicare (Hospital Insurance)	No limit
Earnings Required for Work Credits (dollars)	
One Work Credit (One Quarter of Coverage)	1,360
Maximum of Four Credits a Year	5,440
Earnings Test Annual Exempt Amount (dollars)	
Under Full Retirement Age for Entire Year	17,640
For Months Before Reaching Full Retirement Age in Given Year	46,920
Beginning with Month Reaching Full Retirement Age	No limit
Maximum Monthly Social Security Benefit for Workers Retiring at Full Retirement Age (dollars)	2,861
Full Retirement Age	66
Cost-of-Living Adjustment (percent)	2.8

a. Self-employed persons pay a total of 15.3 percent—12.4 percent for OASDI and 2.9 percent for Medicare.
b. This rate does not reflect the additional 0.9 percent in Medicare taxes certain high-income taxpayers are required to pay. See IRS information on this topic.

Supplemental Security Income (SSI)

Monthly Federal Payment Standard (dollars)	
Individual	771
Couple	1,157
Cost-of-Living Adjustment (percent)	2.8
Resource Limits (dollars)	
Individual	2,000
Couple	3,000
Monthly Income Exclusions (dollars)	
Earned Income [a]	65
Unearned Income	20
Substantial Gainful Activity (SGA) Level for the Nonblind Disabled (dollars)	1,220

a. The earned income exclusion consists of the first $65 of monthly earnings, plus one-half of remaining earnings.

Office of Retirement and Disability Policy
www.ssa.gov/policy

Produced and published at U.S. taxpayer expense

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1309
Supplemental
February Update

Duke Energy Progress - (926) Employee Pensions and Benefits - 12 Months Ended December 31, 2018

Line No.	Account & Description	Total	
1			
2	0926000 - Empl Pensions and Benefits	$ 139,167,551	[1]
3	0926420 - Employees' Tuition Refund	899	[1]
4	0926430 - Employees'Recreation Expense	8,983	[1]
5	0926600 - Employee Benefits - Transferred	(5,967,422)	[1]
6	Total	$ 133,210,011	

[1] E-1 Item 2, Working Trial Balance

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1310
Supplemental
February Update

Variable Short and Long Term Pay for Duke Energy Progress - 12 Months Ended Dec 31, 2018

Line No.	Description	Total Progress	
1			
2	Level of variable short term pay	$ 70,742	[1]
3	Level of variable long term pay	17,004	[2]
4	Total (L2 + L3)	$ 87,747	
5			
6	2019 target level of variable short term pay	$ 69,054	[3]
7	2019 target level of variable long term pay	18,657	[2]
8	Total (L6 + L7)	$ 87,711	
9			
10	Adjustment to restate variable short and long term pay at target (L8 - L4)	$ (35)	

[1] NC-1310-1 - Level of Variable Short Term Pay for Duke Energy Progress - 12 Months Ended Dec 31, 2018, Line 39, Col. (c)
[2] NC-1310-3 - Variable Long Term Pay for Duke Energy Progress, Lines 6 and 13, Col. (a)
[3] NC-1310-2 - 2019 Target Level of Variable Short Term Pay for Duke Energy Progress, Line 39, Col. (c)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1310-1
Supplemental
February Update

Level of Variable Short Term Pay for Duke Energy Progress - 12 Months Ended December 31, 2018

Line No.	Description	Asset	Indirect	Liability	Other Balance Sheet	Capital	O&M	Total
1					(a)	(b)	(c)	(d)
2	Direct Charge:							
3	Duke Energy Commercial Enterprises	$ -	$ 86	$ 38	$ 125	$ 110	$ 3,008	$ 3,243
4	Duke Energy Business Services	1,957,725	951,343	131,012	3,040,081	2,829,696	7,485,974	13,355,751
5	Duke Energy Carolinas	49,707	125,170	134,323	309,201	1,681,795	3,492,564	5,483,560
6	Duke Energy Indiana	2	-	487	488	12,206	103,201	115,896
7	Duke Energy Kentucky	-	-	-	-	8	8,396	8,404
8	Duke Energy Ohio	-	-	678	678	399	44,550	45,626
9	Piedmont Natural Gas	14	-	1,767	1,781	-	9,106	10,887
10	Duke Energy Progress	234,576	3,622,776	57,692	3,915,043	10,283,443	40,588,987	54,787,474
11	Duke Energy Florida	368	4,997	35,183	40,548	14,215	245,580	300,342
12	Direct Charge Total (Sum L3 through L11)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,821,873	$ 51,981,366	$ 74,111,183
13								
14	Percentage split between capital and O&M for direct charges					22.1874%	77.8126%	100.0000%
15								
16	Service Company Allocation:							
17	Duke Energy Commercial Enterprises	$ -	$ -	$ -	$ -	$ -	$ 274	$ 274
18	Duke Energy Business Services	-	-	-	-	131,695	10,813,474	10,945,168
19	Duke Energy Carolinas	-	-	-	-	17,099	3,118,741	3,135,839
20	Duke Energy Indiana	-	-	-	-	24	1,453	1,477
21	Duke Energy Kentucky	-	-	-	-	-	-	-
22	Duke Energy Ohio	-	-	-	-	-	(233)	(233)
23	Piedmont Natural Gas	-	-	-	-	-	4,542	4,542
24	Duke Energy Progress	-	-	-	-	3,267	(919,254)	(915,987)
25	Duke Energy Florida	-	-	-	-	938	55,521	56,459
26	Service Company Allocation Total (Sum L17 through L25)	$ -	$ -	$ -	$ -	$ 153,022	$ 13,074,517	$ 13,227,539
27								
28	Percentage split between capital and O&M for allocated					1.1568%	98.8432%	100.0000%
29								
30	Total (L12 + L26)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,974,895	$ 65,055,883	$ 87,338,722
31								
32	Percentage split between capital and O&M for total					18.7114%	81.2886%	100.0000%
33								
34	Summary:							
35	Direct (L12)				$ 7,307,945	$ 14,821,873	$ 51,981,366	$ 74,111,183
36	Re-assignment of direct 'other' (-L36, Col. (a) x L14)				(7,307,945)	1,621,443	5,686,502	-
37	Allocated (L26)				0	153,022	13,074,517	13,227,539
38	Re-assignment of allocated "other"				-	0	0	(0)
39	Total (Sum L35 through L38)				$ 0	$ 16,596,338	$ 70,742,384	$ 87,338,722

Source: Duke Energy Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1310-2
Supplemental
February Update

2019 Target Level of Variable Short Term Pay for Duke Energy Progress

Line No.	Description	Asset	Indirect	Liability	Other Balance Sheet	Capital	O&M	Total
1					(a)	(b)	(c)	(d)
2	Direct Charge:							
3	Duke Energy Commercial Enterprises	$ -	$ 86	$ 38	$ 125	$ 110	$ 3,008	$ 3,243
4	Duke Energy Business Services	1,957,725	951,343	131,012	3,040,081	2,829,696	7,485,974	13,355,751
5	Duke Energy Carolinas	49,707	125,170	134,323	309,201	1,681,795	3,492,564	5,483,560
6	Duke Energy Indiana	2	-	487	488	12,206	103,201	115,896
7	Duke Energy Kentucky	-	-	-	-	8	8,396	8,404
8	Duke Energy Ohio	-	-	678	678	399	44,550	45,626
9	Piedmont Natural Gas	14	-	1,767	1,781	-	9,106	10,887
10	Duke Energy Progress	234,576	3,622,776	57,692	3,915,043	10,283,443	38,941,620	53,140,107
11	Duke Energy Florida	368	4,997	35,183	40,548	14,215	245,580	300,342
12	Direct Charge Total (Sum L3 through L11)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,821,873	$ 50,333,999	$ 72,463,816
13								
14	Percentage split between capital and O&M for direct charges					22.7483%	77.2517%	100.0000%
15								
16	Service Company Allocation:							
17	Duke Energy Commercial Enterprises	$ -	$ -	$ -	$ -	$ -	$ 274	$ 274
18	Duke Energy Business Services	-	-	-	-	131,695	10,813,474	10,945,168
19	Duke Energy Carolinas	-	-	-	-	17,099	3,118,741	3,135,839
20	Duke Energy Indiana	-	-	-	-	24	1,453	1,477
21	Duke Energy Kentucky	-	-	-	-	-	-	-
22	Duke Energy Ohio	-	-	-	-	-	(233)	(233)
23	Piedmont Natural Gas	-	-	-	-	-	4,542	4,542
24	Duke Energy Progress	-	-	-	-	3,267	(919,254)	(915,987)
25	Duke Energy Florida	-	-	-	-	938	55,521	56,459
26	Service Company Allocation Total (Sum L17 through L25)	$ -	$ -	$ -	$ -	$ 153,022	$ 13,074,517	$ 13,227,539
27								
28	Percentage split between capital and O&M for allocated					1.1568%	98.8432%	100.0000%
29								
30	Total (L12 + L26)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,974,895	$ 63,408,516	$ 85,691,355
31								
32	Percentage split between capital and O&M for total					19.1047%	80.8953%	100.0000%
33								
34	Summary:							
35	Direct (L12)				$ 7,307,945	$ 14,821,873	$ 50,333,999	$ 72,463,816
36	Re-assignment of direct 'other' (-L36, Col. (a) x L14)				(7,307,945)	1,662,433	5,645,511	-
37	Allocated (L26)				0	153,022	13,074,517	13,227,539
38	Re-assignment of allocated "other"				(0)	0	0	-
39	Total (Sum L35 through L38)				$ -	$ 16,637,328	$ 69,054,027	$ 85,691,355

Source: Duke Energy Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1310-3
Supplemental
February Update

Variable Long Term Pay for Duke Energy Progress

Line No.	Description	Total	Performance Awards	Phantom	Restricted Stock Units	Options
1		(a)	(b)	(c)	(d)	(e)
2	Stock-Based Compensation - Actuals - 12 Months Ended December 31, 2018					
3						
4	Grand total - gross	$ 18,456,566	$ 8,116,997	$ -	$ 10,339,568	$ -
5	Less: capital	1,452,248	214,921	-	1,237,327	-
6	Stock-based compensation, net EBIT	$ 17,004,317	$ 7,902,076	$ -	$ 9,102,241	$ -
7						
8						
9	Ongoing Stock-Based Compensation					
10						
11	Grand total - gross	$ 19,474,900	$ 7,380,304	$ -	$ 12,094,595	$ -
12	Less: capital	817,473	131,263	-	686,210	-
13	Stock-based compensation, net EBIT	$ 18,657,427	$ 7,249,041	$ -	$ 11,408,386	$ -

Note: Totals may not foot due to rounding.
Source: Duke Energy Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1311
Supplemental
February Update

Adjustment to Annualize Ernst & Young outside tax services contract

Line No.	Description		Total Company	DEP Allocation			Total DEP
1	E&Y outside tax services in 2019	$	7,586,926	23.2600%	[1]	$	1,764,719
2	Total costs for E&Y outside tax services in 2018		2,533,332	23.3500%	[2]		591,533
3	Adjustment to annual expense for E&Y outside tax services	$	5,053,594			$	1,173,186

[1] 2019 Service Company Cost Allocation
[2] 2018 Service Company Cost Allocation
Source - Duke Energy Progress - Corporate Services Business Support

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018

NC-1400
Supplemental
January Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts operation and maintenance expense and income taxes for changes in benefit costs.

The impact to operation and maintenance expense reflects the annual level of pension, OPEB, Active Medical, FAS112 and non-qualified pension benefits based on a report from the Company's third party consultant, less actual amounts in the test period for these expenses. An adjustment to OPEB to remove terminating prior service credit and an adjustment to both Pension and OPEB for changes due to the new accounting standard ASU 2017-07 are included.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

January Update

Updated NC-1401 through NC-1405 to the 2020 projected costs based on the 2019 actuarial report

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1400
Supplemental
January Update

Line No.	Description	Source	Total NC Retail January	Application	Change
1			January	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance:				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.	NC-1401	(6,358)	(3,060)	(3,298)
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1401	1,473	709	764
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(4,885)	(2,351)	(2,534)
18					
19	Operating Income	L4 - L17	$ 4,885	$ 2,351	$ 2,534
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1401
Supplemental
January Update

Line No.	Benefits by Category	12 Months Ended December 2018 Total		2020 Projection		Adjustment	NC Retail Allocation		Total NC Retail
1									
2	Benefits provided to Duke Energy Progress charged to Duke Energy Progress:								
3	Qualified Pension	$ 6,495	[1]	$ (3,952)	[1]				
4	OPEB and Active Medical	62,155	[2]	62,528	[2]				
5	FAS 112	3,783	[3]	2,796	[3]				
6	Non-Qualified	2,086	[4]	1,904	[4]				
7	Total (L3 to L6)	$ 74,519		$ 63,275					
8									
9	Benefits provided to Duke Energy Business Services (DEBS) allocated to Duke Energy Progress:								
10	Qualified Pension	$ 4,370	[1]	$ 566	[1]				
11	OPEB	15,264	[2]	16,549	[2]				
12	FAS 112	461	[3]	909	[3]				
13	Non-Qualified	1,948	[4]	2,505	[4]				
14	Total (L10 to L13)	$ 22,043		$ 20,530					
15									
16									
17	Percent of incurred costs charged to electric expense for All - Except Non-Qualified	75.98%	[5]	75.98%	[5]				
18	Percent of incurred costs charged to electric expense for Non-Qualified	100.00%		100.00%					
19									
20	Total Pension, OPEB and Active Medical and FAS112 to expense ((L3 to L5)+(L10 to L12))* L17	$ 70,298		$ 60,321		$ (9,977)			
21	Total Non-Qualified to expense (L6 + L13)* L18	4,034		4,409		375			
22	Impact to O&M - total benefits adjustment (L20 + L21)	$ 74,333		$ 64,731		$ (9,602)	66.2120%	[6]	$ (6,358)
23									
24	Statutory tax rate					23.1693% [7]			23.1693%
25	Impact to income taxes (-L22 x L24)					$ 2,225			$ 1,473
26									
27	Impact to operating income (-L22 - L25)					$ 7,377			$ 4,885

[1] NC-1402 - Summary of Pension Expenses, Lines 3, 8
[2] NC-1403 - Summary of OPEB and Active Medical Expenses, Lines 3 + 13, Line 8 + Line 18
[3] NC-1404 - Summary of FAS112 Expenses, Lines 3, 8
[4] NC-1405 - Summary of Non-Qualified Pension Expenses, Lines 3, 8
[5] NC-1301 Line 16
[6] NC Retail Allocation Factor - LAB
[7] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Note: Totals may not foot due to rounding

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018

NC-1402
Supplemental
January Update

Summary of Pension Expenses

Line No.	Description	12 Months Ended December 2018 Total	2020 Projection
1			
2	Duke Energy Progress:		
3	Qualified Pension	$ 6,495,232	$ (3,951,999)
4			
5	Duke Energy Business Services (DEBS):		
6	Duke Energy Retirement Cash Balance Plan	$ 24,310,049	$ 2,406,631
7	Percentage charged to Duke Energy Progress from DEBS	17.98%	23.53%
8	Amount charged to Duke Energy Progresss from DEBS (L6 x L7)	$ 4,370,347	$ 566,280
9			
10	Total Duke Energy Progress pension expenses (L3 + L8)	$ 10,865,579	$ (3,385,719)

Source: Duke Energy Corporate Accounting
Note: Totals may not foot due to rounding

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018

NC-1403
Supplemental
January Update

Summary of OPEB Expenses and Active Medical

Line No.	Description	12 Months Ended December 2018 Total	2020 Projection
1			
2	Duke Energy Progress:		
3	OPEB	$ 5,961,871	$ 4,594,451
4			
5	Duke Energy Business Services:		
6	OPEB	$ 1,824,063	$ (196,876)
7	Percentage charged to Duke Energy Progress from DEBS	17.98%	23.53%
8	Amount charged to Duke Energy Progress from DEBS (L3 x L7)	$ 327,921	$ (46,325)
9			
10	Total Duke Energy Progress Adjusted OPEB expenses (excluding medical, see below) (L3 + L8)	$ 6,289,792	$ 4,548,126
11			
12	Duke Energy Progress:		
13	Active Medical	$ 56,192,678	$ 57,933,057
14			
15	Duke Energy Business Services:		
16	Active Medical	$ 83,082,009	$ 92,310,970
17	Percentage charged to Duke Energy Progress from DEBS	17.98%	17.98%
18	Amount charged to Duke Energy Progress from DEBS (L16 x L17)	$ 14,936,094	$ 16,595,233
19			
20	Total Duke Energy Progress Active Medical expenses (L13 + L18)	$ 71,128,772	$ 74,528,290
21			
22	Total Duke Energy Progress Adjusted OPEB and Active Medical expenses	$ 77,418,564	$ 79,076,416

Source: Duke Energy Corporate Accounting
Note: Totals may not foot due to rounding

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018

NC-1404
Supplemental
January Update

Summary of FAS112 Expenses

Line No.	Description	12 Months Ended December 2018 Total	2020 Projection
1			
2	Duke Energy Progress:		
3	FAS 112	$ 3,783,122	$ 2,795,628
4			
5	Duke Energy Business Services:		
6	FAS 112	$ 2,562,669	$ 5,058,756
7	Percentage charged to Duke Energy Progress from DEBS	17.98%	17.98%
8	Amount charged to Duke Energy Progresss from DEBS (L6 x L7)	$ 460,705	$ 909,439
9			
10	Total Duke Energy Progress FAS 112 expenses (L3 + L8)	$ 4,243,827	$ 3,705,067

Source: Duke Energy Corporate Accounting
Note: Totals may not foot due to rounding

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update benefits costs
For the test period ended December 31, 2018

NC-1405
Supplemental
January Update

Summary of Non-Qualified Pension Expenses

Line No.	Description	12 Months Ended December 2018 Total	2020 Projection
1			
2	Duke Energy Progress:		
3	Non-Qualified Pension	$ 2,086,427	$ 1,904,022
4			
5	Duke Energy Business Services:		
6	Non-Qualified Pension	$ 10,834,340	$ 10,647,967
7	Percentage charged to Duke Energy Progress from DEBS	17.98%	23.53%
8	Amount charged to Duke Energy Progresss from DEBS (L6 x L7)	$ 1,947,747	$ 2,505,467
9			
10	Total Duke Energy Progress Non-Qualified pension expenses (L3 + L8)	$ 4,034,174	$ 4,409,489

Source: Duke Energy Corporate Accounting
Note: Totals may not foot due to rounding

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Levelize nuclear refueling outage costs
For the test period ended December 31, 2018

NC-1500
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expenses and income taxes to levelize nuclear refueling outage costs.

The impact to operation and maintenance expenses was determined by subtracting annualized outage amortization expense from test period outage expense.

The impact to income taxes was determined by multiplying taxable income by the statutory tax rate.

December Update

Updated 1501 with latest Harris Unit 1 outage timing - new amortization to be updated in January 2020 submission.

January Update

Updated 1501 with latest Harris Unit 1 outage timing - new amortization updated in January 2020.

February Update

No updates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Levelize nuclear refueling outage costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1500
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1			February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.	NC-1501	(6,190)	(6,232)	42
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1501	1,434	1,444	(10)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(4,756)	(4,788)	32
18					
19	Operating income	L4 - L17	$ 4,756	$ 4,788	$ (32)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Levelize nuclear refueling outage costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1501
Supplemental
February Update

Line No.	Description			Total System	NC Retail Allocation	Total NC Retail	
1							
2	NC Amortization of Outage Deferral - Last Known and Measurable Outage:						
3	Brunswick Unit 1					$ 664	[1]
4	Brunswick Unit 2					542	[1]
5	Harris Unit 1					786	[1]
6	Robinson Unit 2					845	[1]
7	Total Monthly Amortization Expense (Sum 3 through L6)					$ 2,836	
8							
9							
10							
11	NC Annualized Amortization Expense, Based on Last Known and Measurable Outage:						
12	Brunswick Unit 1	Mar-18	[4]			$ 7,965	
13	Brunswick Unit 2	Mar-19	[4]			6,501	
14	Harris Unit 1	Oct-19	[4]			9,428	
15	Robinson Unit 2	Sep-18	[4]			10,139	
16	Total Annual Amortization Expense (Sum L12 through L15)					$ 34,034	
17							
18							
19	Annualized NC Outage Amortization Expense (L16)					$ 34,034	
20	Test Year Amortization of Outage Deferral					40,225	[2]
21	Impact to O&M (L19 - L20)					$ (6,190)	
22							
23	Statutory tax rate					23.1693%	[3]
24							
25	Impact to income taxes (-L21 x L23)					$ 1,434	
26							
27	Impact to operating income (-L21 - L25)					$ 4,756	

[1] Information provided by Duke Energy Progress Accounting and Reporting
[2] Rates, DEP Surveillance Reporting
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[4] Outage Start Date

Note: Totals may not foot due to rounding

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize rate case costs
For the test period ended December 31, 2018

NC-1600
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expense and income taxes for the amortization of rate case costs.

The impact to operation and maintenance expense is determined as follows:
An annual level of rate case expense is projected based on actual expenses incurred through November 2019 and projected expenses through August 2020.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update:
NC-1602 - updated actuals through October 2019

November update:
NC-1602 - updated actuals through November 2019

December update:
NC-1602 - updated actuals through December 2019

January update:
NC-1602 - updated actuals through January 2020

February update:
NC-1602 - updated actuals through February 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize rate case costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1600
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-1601	701	701	-
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1601	(162)	(162)	-
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	539	539	-
18					
19	Operating income	L4 - L17	$ (539)	$ (539)	$ -
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		2,670	2,670	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		(619)	(619)	-
39	Operating reserves				
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ 2,051	$ 2,051	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize rate case costs
For the test period ended December 31, 2018

NC-1601
Supplemental
February Update

Line No.	Description	Total NC Retail	
1			
2	NC Retail expenses incurred through February 2020	$ 2,539	[1]
3	NC Retail projected expenses (March 2020 through August 2020)	966	[1]
4	NC Retail rate case expenses total	$ 3,505	
5	Amortization period in years	5	
6	Impact to O&M (L4 / L5)	$ 701	
7			
8	Statutory tax rate	23.1693%	[2]
9	Impact to income taxes (-L6 x L8)	$ (162)	
10			
11	Impact to operating income (-L6 - L9)	$ (539)	
12			
13	Impact to Rate Base	NC Retail	
14			
15	Deferral of NC Retail rate case expenses (L4)	$ 3,505	
16	Less test year expenses included in 12/31/2018 balance	(134)	[1]
17	Less first year of amortization (-L6)	(701)	
18	Projected Working Capital after first year of amortization (L15 + L16 + L17)	$ 2,670	
19			
20	Adjustment to Working Capital (L18)	$ 2,670	
21			
22	Change in ADIT on Working Capital (-L18 x L8)	$ (619)	

[1] NC-1602 - NC Retail Rate Case Expenses Incurred/Projected Through August 2020
[2] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize rate case costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1602
Supplemental
February Update

NC Retail Rate Case Expenses Incurred/Projected Through August 2020

Account & Descr: 0186195 - DEFERRED RATE CASE EXPENSE
OU & Descr: NCRP - Carolinas Rates - DEP
Process: NCRTCSE

Line No.	Year			
1	2018 Jan	$	25,410	
2	Feb		-	
3	Mar		789	
4	Apr		617	
5	May		941	
6	Jun		1,130	
7	Jul		341	
8	Aug		68	
9	Sep		2,884	
10	Oct		34,618	
11	Nov		28,576	
12	Dec		38,505	
13	*Subtotal 2018 expenses*	$	133,878	
14	2019 Jan		31,329	
15	Feb		32,997	
16	Mar		63,198	
17	Apr		71,628	
18	May		158,528	
19	Jun		95,766	
20	Jul		109,457	
21	Aug		165,098	
22	Sep		182,996	
23	Oct		168,504	
24	Nov		276,349	
25	Dec		282,777	
26	2020 Jan		455,840	
27	2020 Feb		310,961	
28	Actuals Total	$	2,539,306	
29	*Projected expenses through August 2020*		965,694	[1]
30	Total NC rate case expenses	$	3,505,000	

[1] Duke Energy Progress - Rate Case Charges and Projection Summary

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1900
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expenses, income taxes, depreciation and amortization expense, electric plant in service and accumulated depreciation to remove the impact of Piedmont and Progress merger costs included in the test period and the impacts in other proformas.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update

NC-1904 - Updated actuals for July - October 2019.

November update

NC-1904 - Updated actuals for November 2019.

December update

NC-1904 - Updated actuals for December 2019.

January update

NC-1904 - Updated actuals for January 2020 and formula error in April and May to sync to orginal filing

February update

NC-1904 - Updated actuals for February 2020.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1900
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-1901	(4,039)	(4,039)	-
11	Depreciation and amortization	NC-1901	(182)	(172)	(10)
12	General taxes	NC-1901	(53)	(53)	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1901	990	988	2
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(3,284)	(3,276)	(8)
18					
19	Operating income	L4 - L17	$ 3,284	$ 3,276	$ 8
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-1901	$ (460)	$ -	$ (460)
29	Accumulated depreciation and amortization	NC-1901	356	347	9
30	Electric plant in service, net	Sum L28 through L29	(104)	347	(451)
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35			-	-	-
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (104)	$ 347	$ (451)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1901
Supplemental
February Update

Line No.	Description	Total Utility		NC Retail Allocation	Total NC Retail
1					
2	Remove Merger Cost to Achieve - A&G	$ (5,594)	[1]	66.2120% [2]	$ (3,704)
3	Remove Merger Cost to Achieve - Customer Accts	(375)	[1]	89.2967% [3]	(335)
4	Impact to O&M (L2 + L3)	$ (5,969)			$ (4,039)
5					
6	Remove Depreciation related to Merger Transmission Plant	$ (305)	[4]	59.6699% [5]	$ (182)
7	Impact to Depreciation and Amortization (L6)	$ (305)			$ (182)
8					
9	Remove General Taxes	$ (80)	[1]	66.2120% [2]	$ (53)
10					
11	Statutory tax rate	23.1693%	[6]		23.1693%
12	Impact to income taxes ((-L4 - L7 - L9) x L11)	$ 1,472			$ 990
13					
14	Impact to operating income (-L4 - L7 - L9 - L12)	$ 4,882			$ 3,284
15					
16	Rate Base investment:				
17	Remove Tranmission Merger Electric Plant in Service	(771)	[4]	59.6699% [5]	$ (460)
18	Remove Tranmission Merger Accumulated Depreciation	597	[4]	59.6699% [5]	356
19	Impact to Rate Base investment (L17 + L18)	$ (174)			$ (104)
20					
21	Impact to rate base (L19)	$ (174)			$ (104)

[1] NC-1902 - Piedmont Cost to Achieve
[2] NC Retail Allocation Factor - LAB - Company Labor Expense
[3] NC Retail Allocation Factor - C1ALL - Number of Customers
[4] NC-1903 - Progress Cost to Achieve
[5] NC Retail Allocation Factor - DTALL - Transmission Demand
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1902
Supplemental
February Update

Piedmont Cost to Achieve

Line No.	Description		Total Utility 12/31/2018
1	0903000 - Cust Records and Collection Exp	$	374,792
2	0903200 - Cust Billing and Acct		175
3	0920000 - A and G Salaries		1,215,937
4	0921100 - Employee Expenses		42,052
5	0921200 - Office Expenses		(27,999)
6	0921400 - Computer Services Expenses		35,520
7	0921540 - Computer Rent (Go Only)		26,857
8	0921980 - Office Supplies and Expenses		50,790
9	0923000 - Outside Services Employed		3,975,934
10	0926000 - Empl Pensions and Benefits		319
11	0926600 - Employee Benefits - Transferred		274,045
12	0930200 - Misc General Expenses		359
13	0930250 - Buy\Sell Transf Employee Homes		30
14	0930940 - General Expenses		27
15	0931001 - Rents - AandG		18
16	0935100 - Maint General Plant-Elec		117
17	Total O&M (Sum L1 through L16)	$	5,968,973
18			
19	0408960 - Allocated Payroll Taxes		80,126
20			
21	Total General Taxes(L19)	$	80,126
22			
23	Total Piedmont Cost to Achieve (L17 + L21)	$	6,049,099

[1] Source: Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1903
Supplemental
February Update

Progress Cost to Achieve Impacts

Line No.	Description	Plant in Service 12/31/2018	Current Rate	Calculated Annual Accrual		Actual 12ME Depr Booked	Difference
1	Impact to Income Statement Line Items						
2	Transmission - Gross Projects	$ 31,094,895 [1]	1.90% [2]	$ 590,803		287,669	$ 303,134
3	Transmission Expansion Projects (TEP) - Impairment Projects - Total	(18,560,135) [1]	1.90% [2]	(352,643)		(287,669) [4]	(64,973)
4	Balance in Plant in Service related to TEP (L2 + L3)	$ 12,534,761		$ 238,160		$ -	$ 238,160
5	Impact of Progress CTA assets to depreciation expense in NC-0802 (L4)						$ 238,160
6							
7				CURRENT		PROPOSED	
8		Plant		Calculated		Calculated	
9		in Service	Current	Annual	Proposed	Annual	Adjustment
10		12/31/2018	Rate	Accrual	Rate	Accrual	Amount
11	Transmission - Gross Projects	$ 31,094,895 [1]	1.90% [2]	$ 590,803	2.23% [3]	$ 693,416	$ 102,613
12	Transmission Expansion Projects (TEP) - Impairment Projects - Fully	(15,918,349) [1]	1.90% [2]	(302,449)	2.23% [3]	(354,979)	(52,531)
13	Transmission Expansion Projects (TEP) - Impairment Projects - Partially	(2,641,786) [1]	0.00%	-	0.00%	-	-
14	Balance in Plant in Service related to TEP (L11 + L12 + L13)	$ 12,534,761		$ 288,354		$ 338,437	$ 50,083
15	Impact of Progress CTA assets to depreciation expense in NC-2602 (L14)						$ 50,083
16							
17		Actual					
18		Net Change					
19		through			Proposed		Depr.
20		2/29/2020			Rate		Exp
21	Electric Plant in Service - Balances	$ 770,652 [1]			2.23% [3]		$ 17,186
22	Impact of Progress CTA assets to depreciation expense in NC-1001 (L21)						$ 17,186
23							
24	Impact to depreciation and amortization (L5 + L15 + L22)						$ 305,429
25							
26		Actual					
27		Net Change					
28		through					Adjustment
29		2/29/2020					Amount
30	Impact to Rate Base Line Items						
31	Electric Plant in Service - Balances	$ 770,652 [1]					$ 770,652
32	Impact of Progress CTA assets to electric plant in service in NC-1002 (L31)						$ 770,652
33							
34	Impact to electric plant in service (L32)						$ 770,652
35							
36	Accumulated Depreciation - Balances	$ (343,723) [1]					$ (343,723)
37	Impact of Progress CTA assets to accumulated depreciation in NC-1003 (L36)						$ (343,723)
38							
39		Plant		Calculated			
40		in Service	Current	Annual		12ME Depr	
41		2/29/2020	Rate	Accrual		Booked	Difference
42	Transmission - Gross Projects	$ 31,095,026 [1]	1.90% [2]	$ 590,805		294,620 [1]	$ 296,186
43	Transmission Expansion Projects (TEP) - Impairment Projects - Total	(17,789,614) [1]	1.90% [2]	(338,003)		(294,620) [1]	(43,383)
44	Balance in Plant in Service related to TEP (L42 + L43)	$ 13,305,412		$ 252,803		$ -	$ 252,803
45	Impact of Progress CTA assets to accumulated depreciation in NC-1006 (-L44)						$ (252,803)
46							
47	Impact to accumulated depreciation (L37 + L45)						$ (596,526)
48							
49	Total net plant (L34 + L47)						$ 174,126

[1] NC-1904 - Progress Cost to Achieve - Monthly Amounts
[2] NC-0802 - Adjustment to Annualize Depreciation Expense at December 31, 2018
[3] NC-2602 - Comparison of Current and Proposed Depreciation as of December 31, 2018
[4] Provided by Asset Accounting
[5] Electric plant in service and accumulated depreciation balances at 12/31/2018 related to the Transmission Expansion Projects are excluded in COSS in lines TRANSMISSION PLANT - FERC MIT REL and DPR TRANS RELATED - FERC MIT REL.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1904
Supplemental
February Update

Progress Cost to Achieve - Monthly Amounts

Line No.	Description	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Net Change
		ACTUALS [1]															
1		a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	n = o - a
2	Electric Plant in Service - Balances																
3	Transmission - Gross Projects	$ 31,094,895	$ 31,094,895	$ 31,095,028	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 131
4	Transmission Expansion Projects (TEP) - Impairment Projects - Fully	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	-
5	Transmission Expansion Projects (TEP) - Impairment Projects - Partially	(2,641,786)	(2,586,748)	(2,531,711)	(2,476,674)	(2,421,637)	(2,366,600)	(2,311,562)	(2,256,525)	(2,201,488)	(2,146,451)	(2,091,413)	(2,036,376)	(1,981,339)	(1,926,302)	(1,871,265)	770,521
6	Balance in Plant in Service related to Transmission Expansion Projects (TEP)	$ 12,534,761	$ 12,589,798	$ 12,644,967	$ 12,700,003	$ 12,755,040	$ 12,810,077	$ 12,865,115	$ 12,920,152	$ 12,975,189	$ 13,030,226	$ 13,085,264	$ 13,140,301	$ 13,195,338	$ 13,250,375	$ 13,305,412	$ 770,652
7																	
8	Accumulated Depreciation - Balances																
9	Accumulated Depreciation related to Transmission Expansion Projects (TEP)	$ (1,278,080)	$ (1,302,632)	$ (1,327,184)	$ (1,351,735)	$ (1,376,287)	$ (1,400,839)	$ (1,425,390)	$ (1,449,942)	$ (1,474,494)	$ (1,499,045)	$ (1,523,597)	$ (1,548,148)	$ (1,572,700)	$ (1,597,252)	$ (1,621,803)	$ (343,723)
10																	
11	Depreciation Expense - Activity																
12	Depreciation Expense on Gross Projects	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	
13	Amortization of Impairment	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	
14	Depreciation Expense related to Transmission Expansion Projects (TEP)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize Severance Costs
For the test period ended December 31, 2018

NC-2000
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expenses and income taxes to remove abnormal severance costs included in the test period and to amortize the abnormal severance costs over three years.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

November update:

Update/refinement to allocation from DEBS on NC-2002; Verifed no true-ups to 2018 atypical severance

December update:

NC-2002 - Updated Atypical severance and retention costs related to 2018 to reflect actual payouts as of December 31, 2019.

January update:

NC-2002 - Updated Atypical severance and retention costs related to 2018 to reflect actual payouts as of January 31, 2020.

February update:

NC-2002 - Updated Atypical severance and retention costs related to 2018 to reflect actual payouts as of February 29, 2020.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize Severance Costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2000
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-2001	(24,140)	(23,366)	(774)
11	Depreciation and amortization				-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2001	5,593	5,414	179
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(18,547)	(17,952)	(594)
18					
19	Operating income	L4 - L17	$ 18,547	$ 17,952	$ 594
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment	NC-2001	21,759	23,297	(1,538)
35					
36					
37	Less:				
38	Accumulated deferred taxes	NC-2001	(5,041)	(5,398)	356
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ 16,717	$ 17,899	$ (1,182)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize Severance Costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2001
Supplemental
February Update

Line No.	Description	Total System		NC Retail Allocation		Total NC Retail	
1							
2	Remove actual severance costs in 2018	$ (52,890)	[1]	66.2120%	[3]	$ (35,020)	
3	Annual amortization related to severance costs	16,431	[2]	66.2120%	[3]	10,879	
4	Impact to O&M (L2 + L3)	$ (36,459)				$ (24,140)	
5							
6	Statutory tax rate	23.1693%	[4]			23.1693%	[4]
7	Impact to income taxes (-L4 x L6)	$ 8,447				$ 5,593	
8							
9	Impact to operating income (-L4 - L7)	$ 28,012				$ 18,547	
10							
11	Working capital investment:						
12	Establish a regulatory asset for severance costs	49,294	[1]	66.2120%	[3]	$ 32,638	
13	Less first year of amortization (-L3)	(16,431)		66.2120%	[3]	(10,879)	
14	Impact to working capital investment (L12)	$ 32,862				$ 21,759	
15							
16	Statutory tax rate	23.1693%	[4]			23.1693%	[4]
17	Impact to accumulated deferred income tax (-L14 x L16)	$ (7,614)				$ (5,041)	
18							
19	Impact to rate base (L14+L17)	$ 25,248				$ 16,717	

[1] NC 2002 - Adjustment to remove severance and retention costs, Line 7
[2] NC 2002 - Adjustment to amortize severance and retention costs, Line 11
[3] NC Retail Allocation Factor - LAB
[4] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize Severance Costs
For the test period ended December 31, 2018

NC-2002
Supplemental
February Update

Adjustment to amortize severance costs

Line No.	Description	Total Duke Energy Progress 12/31/2018	Total Duke Energy Progress 12/31/2019	[2]
1	Atypical severance costs related to 2018 - Duke Energy Progress	$ 41,393,957	$ 39,225,389	[1]
2	Atypical severance costs related to 2018 - Allocated from DEBS	11,391,691	10,068,207	[1]
3	Total Atypical severance costs related to 2018 (L1+L2)	$ 52,785,648	$ 49,293,596	
4				
5	Atypical retention costs related to 2018	104,316	-	[3]
6				
7	Total Atypical severance and retention costs related to 2018 (L1+L2)	$ 52,889,964	$ 49,293,596	
8				
9	Years to amortize costs		3	
10				
11	Annual amortization related to severance costs (L3/L5)		$ 16,431,199	

[1] Information provided by Duke Energy Corporate Accounting

[2] Actual payouts made as of February 29, 2020 related to the 2018 atypical severance costs. Approximately 4 employees who elected to participate in the severance plan remain under employment, with additional costs expected during 2020.

[3] Atypical retention in 2018 related to the Tax Department transition to Ernst and Young. Removing to normalize the test year.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018

NC-2200
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts income taxes to reflect the tax impact that results from annualizing interest expense based on the end-of-period, adjusted rate base.

The impact to income taxes was determined as follows:

First, multiply rate base after all pro-forma adjustments have been made by the long-term debt ratio to calculate an adjusted long-term debt balance. Second, multiply the adjusted long-term debt balance by the end of year cost of long-term debt to calculate annualized interest expense. Third, subtract interest expense incurred during the test period from annualized interest expense and multiply the difference by the statutory tax rate.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2200
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2201	786	123	663
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	786	123	663
18					
19	Operating income	L4 - L17	$ (786)	$ (123)	$ (663)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2201
Supplemental
February Update

Line No.	Description	Total System Col [a]		NC Retail Allocation Col [b]		Total NC Retail Col [c]	
1							
2	Rate base before pro forma adjustments	$ 14,580,739	[1]	67.6169%	[2]	$ 9,859,050	[1]
3							
4	Pro forma rate base before working capital adjustment	$ 15,774,079	[3]			$ 10,665,950	
5							
6	Long-term debt ratio	47.0000%	[4]			47.0000%	[4]
7	Calculated long-term debt (L4 x L6)	$ 7,413,817				$ 5,012,997	
8							
9	End of year cost of long-term debt	4.1546%	[4]			4.1546%	[4]
10	Annualized interest expense (L7 x L9)	$ 308,011				$ 208,268	
11							
12	Incurred interest expense	315,466	[5]	67.0949%	[6]	211,661	
13	Less interest on customer deposits	(8,643)	[7]			(7,971)	[7]
14	Net interest expense	306,823				203,690	
15							
16	Increase / <decrease> to interest costs (L10 - L14)	$ 1,188				$ (3,394)	
17							
18	Statutory tax rate	23.1693%	[8]			23.1693%	[8]
19	Impact to income taxes (-L16 x L18)	$ (275)				$ 786	
20							
21	Impact to operating income (-L19)	$ 275				$ (786)	

[1] Smith Exhibit 1, Page 1, Line 12
[2] NC Retail Allocation Factor - Calculation: L2, Col [c] / L2, Col [a]
[3] Calculation: L4, Col [c] / L2, Col [b]
[4] Smith Exhibit 1, Page 2, Line 1
[5] Cost of Service, E-1 Item 45a, Total Other Interest Expense, Line 702
[6] NC Retail Allocation Factor - Net Book Plant
[7] Smith Exhibit 1, Page 1, Line 7
[8] NC-0104 - 2019 Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018

NC-2300
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required as a result of the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 order in Docket No. M-100 Sub 137.

October Update

Reflects changes for October updates to actuals

November Update

Reflects changes for November actuals

December Update

Reflects changes for December actuals

January Update

Reflects changes for January 2020 actuals

February Update

Reflects changes for February 2020 actuals and revised E&Y Lead Lag Study

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2300
Supplemental
February Update

Line No.	Description	Source	February Present	February Proposed	Total NC Retail Application Present	Total NC Retail Application Proposed	Change Present	Change Proposed
1								
2	**Pro Formas Impacting Income Statement Line Items**							
3								
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -
5								
6	Electric operating expenses:							
7	Operation and maintenance							
8	Fuel used in electric generation		-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-
14	Income taxes	NC-2301 & NC-2302	96	(307)	122	(337)	(27)	30
15	Amortization of investment tax credit		-	-	-	-	-	-
16								
17	Total electric operating expenses	Sum L8 through L15	96	(307)	122	(337)	(27)	30
18								
19	Operating income	L4 - L17	$ (96)	$ 307	$ (122)	$ 337	$ 27	$ (30)
20								
21	Notes:							
22	Revenue: positive number increases revenue / negative number decreases revenue							
23	Expense: positive number increases expense / negative number decreases expense							
24								
25								
26	**Pro Formas Impacting Rate Base Line Items**							
27								
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-
31								
32	Add:							
33	Materials and supplies		-	-	-	-	-	-
34	Working capital investment	NC-2302	(21,145)	67,827	(27,013)	74,407	5,868	(6,580)
35								
36								
37	Less:							
38	Accumulated deferred taxes		-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-
40								
41								
42	Construction work in progress		-	-	-	-	-	-
43								
44	Total impact to rate base	Sum L30 through L42	$ (21,145)	$ 67,827	$ (27,013)	$ 74,407	$ 5,868	$ (6,580)
45								
46	Note:							
47	Rate Base: positive number increases rate base / negative number decreases rate base							

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Supplemental
February Update

		NC Retail											
		Financials					Iteration 1						
Line No.	Description	Adjusted with CWC (a)		Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)		Increase (d) = (e) - (a)		With Increase (e) = (a) + (d)		Weighted Lead Lag Days (f)	
1	Total Adjusted Present Revenue	$ 3,361,009	[1]								42.09	[1]
2	Revenue Increase (L3)	-		534,343			528,177				41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009		534,343	3,895,352		528,177		3,889,186		42.06	[8]
4												
5	Operating Expenses:											
6	Fuel Used in Electric Generation	851,667	[1]	-	851,667				851,667		28.49	[1]
7	Purchased Power	156,798	[1]	-	156,798				156,798		33.44	[1]
8												
9	Operation & Maintenance Expense	863,429	[1]								37.40	[1]
10	Revenue Increase (L11)			1,972			1,949				37.32	[7]
11	Operation and Maintenace Expense with Increase	863,429		1,972	865,402		1,949	[3]	865,379		37.40	[8]
12												
13	Total Adjusted Depreciation and Amortization	950,060	[1]	-	950,060				950,060		0.00	[1]
14	Total Adjusted General Taxes	102,506	[1]	-	102,506				102,506		137.62	[1]
15	Total Adjusted Interest on Customer Deposits	7,971	[1]	-	7,971				7,971		137.50	[1]
16												
17	Net Income Taxes	47,541	[1]								6.83	[1]
18	Revenue Increase (L19)			123,040			121,923				-20.60	[7]
19	Income Taxes with Increase	47,541		123,040	170,581		121,923	[4]	169,465		-12.90	[8]
20												
21	Amortization of Investment Tax Credit	(3,614)	[1]	-	(3,614)				(3,614)		0.00	[1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,976,358		125,012	3,101,370		123,873		3,100,231		24.15	[9]
23												
24	Income for Return (L3 - L22)	384,651		409,331	793,982		404,304		788,955	[5]	23.10	[9]
25	Interest Expense	207,855	[1]	1,324	209,179		-		207,855	[6]	87.70	[1]
26	Return for Equity (L24 - L25)	176,796		408,007	584,803		404,304		581,100		0.00	[1]
27												
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009			$ 3,895,352				$ 3,889,186		23.94	[9]
29												
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,644,806	[1]	$ 67,827	$ 10,712,632				$ 10,644,806			
31												
32	Overall Rate of Return (L24 / L30)	3.61%			7.41%				7.41%			
33	Target Rate of Return	7.41%	[2]		7.41%	[2]			7.41%	[2]		
34												
35				Revenue	Adjusted							
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted		Increase	w/Increase							
37	Annual Requirement (L3 and/or L28)	$ 3,361,009			$ 3,895,352				$ 3,889,186			
38	Daily Requirement (L37 / 365 Days)	$ 9,208			$ 10,672				$ 10,655			
39	Net Lag Days	13.65	[1]		18.13				18.12			
40												
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,656		$ 67,827	$ 193,483		$ 67,379		$ 193,036			
42	Add: Working Capital Related to NC Sales Tax	$ 4,760	[1]		$ 4,760	[1]						
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,416		$ 67,827	$ 198,243							

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Supplemental
February Update

		NC Re					NC Retail					
		Financials					Iteration 2					
Line No.	Description	Adjusted with CWC (a)		Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)		Increase (g) = (h) - (e)		With Increase (h) = (e) + (g)		Weighted Lead Lag Days (i)	
1	Total Adjusted Present Revenue	$ 3,361,009	[1]								42.09	[1]
2	Revenue Increase (L3)	-		534,343			6,126				41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009		534,343	3,895,352		6,126		3,895,311		42.06	[8]
4												
5	Operating Expenses:											
6	Fuel Used in Electric Generation	851,667	[1]	-	851,667				851,667		28.49	[1]
7	Purchased Power	156,798	[1]	-	156,798				156,798		33.44	[1]
8												
9	Operation & Maintenance Expense	863,429	[1]								37.40	[1]
10	Revenue Increase (L11)			1,972			23		23		37.32	[7]
11	Operation and Maintenace Expense with Increase	863,429		1,972	865,402		23	[3]	865,401		37.40	[8]
12												
13	Total Adjusted Depreciation and Amortization	950,060	[1]	-	950,060				950,060		0.00	[1]
14	Total Adjusted General Taxes	102,506	[1]	-	102,506				102,506		137.62	[1]
15	Total Adjusted Interest on Customer Deposits	7,971	[1]	-	7,971				7,971		137.50	[1]
16												
17	Net Income Taxes	47,541	[1]								6.83	[1]
18	Revenue Increase (L19)			123,040			1,109				-20.60	[7]
19	Income Taxes with Increase	47,541		123,040	170,581		1,109	[4]	170,574		-12.95	[8]
20												
21	Amortization of Investment Tax Credit	(3,614)	[1]	-	(3,614)				(3,614)		0.00	[1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,976,358		125,012	3,101,370		1,132		3,101,363		24.14	[9]
23												
24	Income for Return (L3 - L22)	384,651		409,331	793,982		4,994		793,949	[5]	23.10	[9]
25	Interest Expense	207,855	[1]	1,324	209,179		1,316		209,171	[6]	87.70	[1]
26	Return for Equity (L24 - L25)	176,796		408,007	584,803		3,678		584,778		0.00	[1]
27												
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009			$ 3,895,352				$ 3,895,311		23.93	[9]
29												
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,644,806	[1]	$ 67,827	$ 10,712,632		$ 67,379		$ 10,712,185			
31												
32	Overall Rate of Return (L24 / L30)	3.61%			7.41%				7.41%			
33	Target Rate of Return	7.41%	[2]		7.41%	[2]			7.41%	[2]		
34												
35				Revenue	Adjusted							
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted		Increase	w/Increase							
37	Annual Requirement (L3 and/or L28)	$ 3,361,009			$ 3,895,352				$ 3,895,311			
38	Daily Requirement (L37 / 365 Days)	$ 9,208			$ 10,672				$ 10,672			
39	Net Lag Days	13.65	[1]		18.13				18.13			
40												
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,656		$ 67,827	$ 193,483		$ 445		$ 193,480			
42	Add: Working Capital Related to NC Sales Tax	$ 4,760	[1]		$ 4,760	[1]						
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,416		$ 67,827	$ 198,243							

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Supplemental
February Update

Line No.	Description	NC Re			NC Retail		
		Financials			Iteration 3		
		Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Increase (j) = (k) - (h)	With Increase (k) = (h) + (j)	Weighted Lead Lag Days (l)
1	Total Adjusted Present Revenue	$ 3,361,009 [1]					42.09 [1]
2	Revenue Increase (L3)	-	534,343		40		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009	534,343	3,895,352	40	3,895,352	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	851,667 [1]	-	851,667		851,667	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,429 [1]					37.40 [1]
10	Revenue Increase (L11)		1,972		0	23	37.32 [7]
11	Operation and Maintenace Expense with Increase	863,429	1,972	865,402	0 [3]	865,402	37.40 [8]
12							
13	Total Adjusted Depreciation and Amortization	950,060 [1]	-	950,060		950,060	0.00 [1]
14	Total Adjusted General Taxes	102,506 [1]	-	102,506		102,506	137.62 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	47,541 [1]					6.83 [1]
18	Revenue Increase (L19)		123,040		7		-20.60 [7]
19	Income Taxes with Increase	47,541	123,040	170,581	7 [4]	170,581	-12.96 [8]
20							
21	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,976,358	125,012	3,101,370	7	3,101,370	24.14 [9]
23							
24	Income for Return (L3 - L22)	384,651	409,331	793,982	33	793,982 [5]	23.10 [9]
25	Interest Expense	207,855 [1]	1,324	209,179	9	209,179 [6]	87.70 [1]
26	Return for Equity (L24 - L25)	176,796	408,007	584,803	24	584,802	0.00 [1]
27							
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009		$ 3,895,352		$ 3,895,352	23.93 [9]
29							
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,644,806 [1]	$ 67,827	$ 10,712,632	$ 445	$ 10,712,629	
31							
32	Overall Rate of Return (L24 / L30)	3.61%		7.41%		7.41%	
33	Target Rate of Return	7.41% [2]		7.41% [2]		7.41% [2]	
34							
35			Revenue	Adjusted			
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
37	Annual Requirement (L3 and/or L28)	$ 3,361,009		$ 3,895,352		$ 3,895,352	
38	Daily Requirement (L37 / 365 Days)	$ 9,208		$ 10,672		$ 10,672	
39	Net Lag Days	13.65 [1]		18.13		18.13	
40							
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,656	$ 67,827	$ 193,483	$ 3	$ 193,483	
42	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,416	$ 67,827	$ 198,243			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Supplemental
February Update

		NC Re					NC Retail					
		Financials					Iteration 4					
Line No.	Description	Adjusted with CWC (a)		Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)		Increase (m) = (n) - (k)		With Increase (n) = (k) + (m)		Weighted Lead Lag Days (o)	
1	Total Adjusted Present Revenue	$ 3,361,009	[1]								42.09	[1]
2	Revenue Increase (L3)	-		534,343			0				41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009		534,343	3,895,352		0		3,895,352		42.06	[8]
4												
5	Operating Expenses:											
6	Fuel Used in Electric Generation	851,667	[1]	-	851,667				851,667		28.49	[1]
7	Purchased Power	156,798	[1]	-	156,798				156,798		33.44	[1]
8												
9	Operation & Maintenance Expense	863,429	[1]								37.40	[1]
10	Revenue Increase (L11)			1,972			0		23		37.32	[7]
11	Operation and Maintenace Expense with Increase	863,429		1,972	865,402		0	[3]	865,402		37.40	[8]
12												
13	Total Adjusted Depreciation and Amortization	950,060	[1]	-	950,060				950,060		0.00	[1]
14	Total Adjusted General Taxes	102,506	[1]	-	102,506				102,506		137.62	[1]
15	Total Adjusted Interest on Customer Deposits	7,971	[1]	-	7,971				7,971		137.50	[1]
16												
17	Net Income Taxes	47,541	[1]								6.83	[1]
18	Revenue Increase (L19)			123,040			0				-20.60	[7]
19	Income Taxes with Increase	47,541		123,040	170,581		0	[4]	170,581		-12.96	[8]
20												
21	Amortization of Investment Tax Credit	(3,614)	[1]	-	(3,614)				(3,614)		0.00	[1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,976,358		125,012	3,101,370		0		3,101,370		24.14	[9]
23												
24	Income for Return (L3 - L22)	384,651		409,331	793,982		0		793,982	[5]	23.10	[9]
25	Interest Expense	207,855	[1]	1,324	209,179		0		209,179	[6]	87.70	[1]
26	Return for Equity (L24 - L25)	176,796		408,007	584,803		0		584,803		0.00	[1]
27												
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009			$ 3,895,352				$ 3,895,352		23.93	[9]
29												
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,644,806	[1]	$ 67,827	$ 10,712,632		$ 3		$ 10,712,632			
31												
32	Overall Rate of Return (L24 / L30)	3.61%			7.41%				7.41%			
33	Target Rate of Return	7.41%	[2]		7.41%	[2]			7.41%	[2]		
34												
35				Revenue	Adjusted							
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted		Increase	w/Increase							
37	Annual Requirement (L3 and/or L28)	$ 3,361,009			$ 3,895,352							
38	Daily Requirement (L37 / 365 Days)	$ 9,208			$ 10,672							
39	Net Lag Days	13.65	[1]		18.13							
40												
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,656		$ 67,827	$ 193,483							
42	Add: Working Capital Related to NC Sales Tax	$ 4,760	[1]		$ 4,760	[1]						
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,416		$ 67,827	$ 198,243							

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Supplemental
February Update

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books (a)	Adjustments (b)	Adjusted Before Change in CWC (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books (f)	Adjustments (g)	Adjusted Before Increase (h) = (f) + (g)
1	Revenue	$ 3,657,503 [1]		$ 3,657,503			42.13 [1]		42.13
2									
3	Rate Schedule Revenue								
4	NC-0100 Annualize Retail revenues for current rates		(201,667) [3]	(201,667)				41.88 [2]	41.88
5	NC-0300 Normalize for weather		(72,510) [3]	(72,510)				41.88 [2]	41.88
6	NC-0400 Annualize revenues for customer growth		(2,159) [3]	(2,159)				41.88 [2]	41.88
7	NC-0500 Eliminate unbilled revenues		11,826 [3]	11,826				41.88 [2]	41.88
8	NC-0600 Adjust costs recovered through non-fuel riders		(27,830) [3]	(27,830)				41.88 [2]	41.88
9	NC-2900 Storm Deferral NC FMD		- [3]	-				41.88 [2]	41.88
10	NC-3000 Adjust Other Revenue		(4,155) [3]	(4,155)				98.96 [2]	98.96
11	Rounding		-	-				41.88 [2]	41.88
12	Revenue - Adjustments (Sum Lines 4 through 11)	-	(296,495)	(296,495)					
13									
14	Total Adjusted Revenue (L1 + L12)	$ 3,657,503	$ (296,495)	$ 3,361,009 [3]	$ -	$ 3,361,009	42.13	(0.05)	42.09 [6]
15									
16	Operating Expenses:								
17	Fuel Used in Electric Generation	$ 881,642 [2]		$ 881,642			28.49 [2]		28.49
18	NC-0200 Update fuel costs to approved rate		11,449 [3]	11,449				28.49 [2]	28.49
19	NC-0300 Normalize for weather		(20,432) [3]	(20,432)				28.49 [2]	28.49
20	NC-0400 Annualize revenues for customer growth		(2,471) [3]	(2,471)				28.49 [2]	28.49
21	NC-0600 Adjust costs recovered through non-fuel riders		(18,522) [3]	(18,522)				28.49 [2]	28.49
22	NC-2900 Storm Deferral NC FMD		- [3]	-				28.49 [2]	28.49
23	Rounding		-	-				28.49 [2]	28.49
24	Fuel Used in Electric Generation - Adjustments (Sum Lines 18 through 23)	-	(29,976)	(29,976)					
25									
26	Total Adjusted Fuel Used in Electric Generation (L17 + L24)	$ 881,642	$ (29,976)	$ 851,667 [3]	$ -	$ 851,667	28.49	0.00	28.49 [6]
27									
28	Purchased Power	$ 158,763 [2]		$ 158,763			33.40 [2]		33.40
29	NC-3500 Adjust purchased power		(1,965) [3]	(1,965)				30.29 [2]	30.29
30	Rounding		-	-					
31	Purchased Power - Adjustments (Sum Lines 29 through 30)	-	(1,965)	(1,965)					
32									
33	Total Adjusted Purchased Power (L28 + L31)	$ 158,763	$ (1,965)	$ 156,798 [3]	$ -	$ 156,798	33.40	0.04	33.44 [6]

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Supplemental
February Update

Line No.	Description	NC Retail							
		Financials					Lead Lag Days		
		Per Books (a)	Adjustments (b)	Adjusted Before Change in CWC (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books (f)	Adjustments (g)	Adjusted Before Increase (h) = (f) + (g)
34									
35	Operation & Maintenance Expense	$ 1,050,819 [2]		$ 1,050,819			37.32 [1]		37.32
36	NC-0100 Annualize Retail revenues for current rates		(744) [3]	(744)				37.32 [2]	37.32
37	NC-0200 Update fuel costs to approved rate		- [3]	-				37.32 [2]	37.32
38	NC-0300 Normalize for weather		(268) [3]	(268)				37.32 [2]	37.32
39	NC-0400 Annualize revenues for customer growth		(8) [3]	(8)				37.32 [2]	37.32
40	NC-0600 Adjust costs recovered through non-fuel riders		(136,143) [3]	(136,143)				37.32 [2]	37.32
41	NC-0700 Adjust O&M for executive compensation		(2,399) [3]	(2,399)				37.07 [2]	37.07
42	NC-1200 Annualize O&M non-labor expenses		1,319 [3]	1,319				33.30 [2]	33.30
43	NC-1300 Normalize O&M labor expenses		(19,794) [3]	(19,794)				37.07 [2]	37.07
44	NC-1400 Update benefits costs		(6,358) [3]	(6,358)				13.97 [2]	13.97
45	NC-1500 Levelize nuclear refueling outage costs		(6,190) [3]	(6,190)				40.52 [2]	40.52
46	NC-1600 Amortize rate case costs		701 [3]	701				0.00 [2]	0.00
47	NC-1700 Adjust aviation expenses		(1,452) [3]	(1,452)				37.32 [2]	37.32
48	NC-1800 Adjust for approved regulatory assets and liabilities		1,603 [3]	1,603				0.00 [2]	0.00
49	NC-1900 Adjust for Merger Related Costs		(4,039) [3]	(4,039)				37.32 [2]	37.32
50	NC-2000 Amortize Severance Costs		(24,140) [3]	(24,140)				37.07 [2]	37.07
51	NC-2500 Adjust for credit card fees		5,307 [3]	5,307				40.52 [2]	40.52
52	NC-2700 Adjust vegetation management expenses		5,757 [3]	5,757				40.52 [2]	40.52
53	NC-2900 Storm Deferral NC		- [3]	-				37.32 [2]	37.32
54	NC-3000 Adjust Other Revenue		(5) [3]	(5)				37.32 [2]	37.32
55	NC-3100 Adjust for change in NCUC Reg Fee		(234) [3]	(234)				93.25 [2]	93.25
56	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(6,413) [3]	(6,413)				37.32 [2]	37.32
57	NC-3300 Adjust for CertainTeed payment Obligation		- [3]	-				37.32 [2]	37.32
58	NC-3400 Amortize deferred balance Asheville Combined Cycle		6,109 [3]	6,109				37.32 [2]	37.32
59			-	-				0.00	0.00
60			-	-				0.00	0.00
61	Rounding		-	-				33.30 [2]	33.30
62	Operation & Maintenance Expense - Adjustments (Sum Lines 36 through 57)	-	(187,389)	(187,389)					
63									
64	Total Adjusted Operation & Maintenance Expense (L35 + L62)	$ 1,050,819	$ (187,389)	$ 863,429 [3]	$ -	$ 863,429	37.32	0.08	37.40 [6]
65									
66	Depreciation and Amortization	$ 669,787 [2]		$ 669,787			0.00 [1]		0.00
67	NC-0200 Update fuel costs to approved rate		- [3]	-				0.00 [2]	0.00
68	NC-0600 Adjust costs recovered through non-fuel riders		(58,446) [3]	(58,446)				0.00 [2]	0.00
69	NC-0800 Annualize Depreciation on year end plant balances		41,407 [3]	41,407				0.00 [2]	0.00
70	NC-1000 Adjust for post test year additions to plant in service		61,840 [3]	61,840				0.00 [2]	0.00
71	NC-1100 Amortize deferred environmental costs		96,023 [3]	96,023				0.00 [2]	0.00
72	NC-1800 Adjust for approved regulatory assets and liabilities		(3,479) [3]	(3,479)				0.00 [2]	0.00
73	NC-1900 Adjust for Merger Related Costs		(182) [3]	(182)				0.00 [2]	0.00
74	NC-2600 Adjust for Depreciation for new rates		88,728 [3]	88,728				0.00 [2]	0.00
75	NC-2800 Adjust reserve for end of life nuclear costs		(91) [3]	(91)				0.00 [2]	0.00
76	NC-2900 Storm Deferral		43,201 [3]	43,201				0.00 [2]	0.00
77	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(304) [3]	(304)				0.00 [2]	0.00
78	NC-3400 Amortize deferred balance Asheville Combined Cycle		11,576 [3]	11,576				0.00 [2]	0.00
79			-	-				0.00 [2]	0.00
80	Rounding		-	-					
81	Depreciation and Amortization - Adjustments (Sum Lines 67 through 80)	-	280,272	280,272					
82									
83	Total Adjusted Depreciation and Amortization (L66 + L81)	$ 669,787	$ 280,272	$ 950,060 [3]	$ -	$ 950,060	0.00	0.00	0.00 [6]

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Supplemental
February Update

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books (a)	Adjustments (b)	Adjusted Before Change in CWC (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books (f)	Adjustments (g)	Adjusted Before Increase (h) = (f) + (g)
84									
85	General Taxes	$ 102,197 [2]		$ 102,197			132.70 [1]		132.70
86	NC-0600 Adjust costs recovered through non-fuel riders		(6,458) [3]	(6,458)				137.26 [2]	137.26
87	NC-0900 Annualize property taxes on year end plant balances		4,064 [3]	4,064				186.50 [2]	186.50
88	NC-1000 Adjust for post test year additions to plant in service		4,963 [3]	4,963				186.50 [2]	186.50
89	NC-1300 Normalize O&M labor expenses		(1,162) [3]	(1,162)				48.41 [2]	48.41
90	NC-1700 Adjust aviation expenses		(18) [3]	(18)				48.41 [2]	48.41
91	NC-1800 Adjust for approved regulatory assets and liabilities		5 [3]	5				48.41 [2]	48.41
92	NC-1900 Adjust for Merger Related Costs		(53) [3]	(53)				48.41 [2]	48.41
93	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(1,032) [3]	(1,032)				186.50 [2]	186.50
94	Rounding		-	-					
95	General Taxes - Adjustments (Sum Lines 86 through 94)	-	309	309					
96									
97	Total Adjusted General Tax (L85 + L95)	$ 102,197	$ 309	$ 102,506 [3]	$ -	$ 102,506	132.70	4.92	137.62 [6]
98									
99	Interest on Customer Deposits	$ 7,971 [2]		$ 7,971			137.50 [1]		137.50
100	Interest on Customer Deposits - Adjustments			-					
101	Rounding		-	-					
102	Total Adjusted Interest on Customer Deposits (L99 + L100)	$ 7,971	$ -	$ 7,971 [3]	$ -	$ 7,971	137.50	0.00	137.50 [6]
103									
104	Income Taxes	$ 112,986 [2]		$ 112,986			(20.60) [1]		(20.60)
105	PF INC TAX-Adjust Income Taxes		(127,312) [3]	(127,312)				(20.60) [2]	(20.60)
106	NC-0600 Adjust costs recovered through non-fuel riders		63,168 [3]	63,168				0.00	0.00
107	NC-2100 Adjust NC income taxes for rate change		(2,183) [3]	(2,183)				(20.60) [2]	(20.60)
108	NC-2200 Synchronize interest expense		786 [3]	786				(20.60) [2]	(20.60)
109	Rounding		-	-					
110	Income Taxes - Adjustments (Sum Lines 105 through 109)	-	(65,540)	(65,540)					
111									
112	Total Adjusted Income Taxes (L104 + L110)	$ 112,986	$ (65,540)	$ 47,446 [3]	$ 96 [5]	$ 47,541	(20.60)	27.42	6.83 [6]
113									
114	Amortization of Investment Tax Credit	$ (2,134) [2]		$ (2,134)			0.00 [1]		0.00
115	NC-0800 Annualize Depreciation on year end plant balances		(1,481) [3]	(1,481)				0.00 [2]	0.00
116	Rounding		-	-					
117	Amort. of Investment Tax Credit - Adjustments (Sum Lines 115 through 116)	-	(1,481)	(1,481)					
118									
119	Total Adjusted Amortization of Investment Tax Credit (L114 + L117)	$ (2,134)	$ (1,481)	$ (3,614) [3]	$ -	$ (3,614)	0.00	0.00	0.00 [6]
120									
121	Total Operating Expense (L26+L33+L64+L83+L97+L102+L112+L119)	$ 2,982,032	$ (5,769)	$ 2,976,263	$ 96	$ 2,976,358	27.48	(1.51)	25.98 [6]
122									
123	Income for Return (L14 - L121)	675,472	(290,725)	384,746	(96)	384,651	27.48	19.99	47.47 [6]
124	Interest Expense	211,661 [2]	(3,394)	208,268 [4]	(413) [4]	207,855	87.70 [2]	0.00	87.70 [2]
125	Return for Equity (L123 - L124)	463,810	(287,332)	176,479	317	176,796	0.00 [2]	0.00	0.00 [2]
126									
127	Total Requirement (L121 + L123 = L14)	$ 3,657,503		$ 3,361,009		$ 3,361,009	27.48	0.96	28.44 [6]
128									
129	RATE BASE	$ 9,859,050 [3]	$ 806,900	$ 10,665,950 [3]	$ (21,145)	$ 10,644,806			
130									
131	Overall Rate of Return (L123 / L129)	6.85%		3.61%		3.61%			

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Supplemental
February Update

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books (a)	Adjustments (b)	Adjusted Before Change in CWC (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books (f)	Adjustments (g)	Adjusted Before Increase (h) = (f) + (g)
132									
133									
134	Calculation of Change in Cash Working Capital (CWC) due to Adjustments	Per Books	Change in CWC	Adjusted					
135	Revenue Lag Days	42.13		42.09					
136	Requirement Lead Days	27.48		28.44					
137									
138	Net Lag Days (L135 - L136)	14.65		13.65					
139									
140	Annual Requirement	$ 3,657,503		$ 3,361,009					
141	Daily Requirement (L140 / 365 Days)	$ 10,021		$ 9,208					
142	Net Lag Days (L138, Rounded Per Books)	14.65		13.65					
143	Est. CWC Req. Before Sales Tax Requirement (L141 x L142)	$ 146,801		$ 125,656					
144									
145	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]					
146									
147	Total Cash Working Capital Requirements (L143 + L145)	$ 151,561	$ (21,145)	$ 130,416					

Notes:
[1] NC 2303 Summary
[2] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag Study
[3] Docket No. E-2, Sub 1219, Smith Exhibit 1
[4] Rate Base x NC-2304-Inputs
[5] Interest Expense: - L124 x Tax Rate: 23.1693%
[6] New weighted averages calculated.

I/A

Smith
Supplemental Exhibit 1

NC-2303
Supplemental
February Update

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the test period ended December 31, 2018
Dollars in Thousands

Revised E-1 Item 14

Line No	Description	Actual Annual Expense [A]	Lead (Lag) Days [B]	Weighted Amount [C]
	Calculation of NC Retail Amount:			
1	Total Revenue Lag	$ (3,657,503)	42.13	$ (154,105,865)
2				
3	Operation & Maintenance Expense	$ 2,091,224	33.30	$ 69,630,312
4	Depreciation and Amortization	669,787	0.00	-
5	Taxes Other Than Income Taxes	102,197	132.70	13,561,920
6	Interest on Customer Deposits	7,971	137.50	1,096,011
7	Net Income Taxes	112,986	-20.60	(2,327,337)
8	ITC	(2,134)	0.00	-
9	Income for Return	675,472	27.48	18,562,554
10	Total Requirements (Sum L3:L9)	$ 3,657,503	27.48	$ 100,523,460
11				
12	Revenue Lag Days (L1)		42.13	
13	Requirements Lead Days (-L10)		-27.48	
14	Net Lag Days (L12 + L13)		14.65	
15	Daily Requirements (Line 9, Col. A divided by 365)			$ 10,020.56
16				
17	Estimated Cash Working Capital Requirements (L14 x L15)			$ 146,801
18	Add: Cash Working Capital Related to NC Sales Tax			4,760
19	Total Cash Working Capital Requirements (L17 + L18)			$ 151,561
20				
21	**Calculation of Total Company and Jurisdictional Amounts:**			
22	NC Retail Factor			67.0949% [1]
23				
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 225,890
25				

[1] NC Retail Allocation Factor - Net Book Plant

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjustment to Cash Working Capital - Input Worksheet
For the test period ended December 31, 2018

NC-2304
Supplemental
February Update

Line No	Description	Rate		Ratio		Weighted	
1	Debt	4.15%	[1]	47.00%	[1]	1.9526%	[2]
2	Equity	10.30%	[1]	53.00%	[1]	5.4590%	[3]
3	Total ROR (L1 + L2)					7.4116%	
4							
5	Statutory tax rate	23.1693%	[4]				
6	Statutory regulatory fee percentage rate	0.1297%	[5]				
7	Uncollectibles rate	0.24%	[6]				

Notes:
[1] Smith Exhibit 1, Page 2
[2] Debt Rate x Debt Ratio
[3] ROE x Equity Ratio
[4] NC-0104 - 2019 Tax Rate, Line 10
[5] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate, Docket No. M-100, Sub 142
[6] NC-0105 - Development of Uncollectibles Rate

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust coal inventory
For the test period ended December 31, 2018

NC-2400
Supplemental
December Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjustment reflects the Company's requirement for a level of coal inventory equal to the coal needed for a 35 day full load burn priced at the projected average delivered coal cost as discussed by Witness Phipps in Docket No. E-2, Sub 1204.

Days of coal inventory on the storage piles refers to "full load burn days". Therefore, one "day" of supply is equal to how much coal would be burned at any given generating unit if it was to run at full load for 24 hours straight. The current full load burn for the entire coal-fired fleet in the Carolinas is 36,049 tons per day which means that if there are 35 days of supply on the system, then there are 1.3M tons on the storage piles.

The Company does not use "average" burn to report how many "days" of inventory is in storage because the average burn for any given period can vary greatly due to many factors and it can over-state the amount of inventory in storage. For example, the biggest risk would be to run out of coal during a hot summer when the entire coal-fired fleet is needed to run at full load. By reporting the inventory using "full load burn", we have stated how many days our units can run during a critical time when they are all expected to be running at full load.

December update:
Aligned "Projected average delivered coal costs per ton" to Docket No. E-2, Sub 1204, Updated Testimony of Brett Phipps from Hearing transcript, adjusted the Fixed transportation cost to the Spring 2019 inbound tons,and updated to reflect the retirement of Asheville units.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust coal inventory
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2400
Supplemental
December Update

Line No.	Description	Source	Total NC Retail December	Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.		-	-	-
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes		-	-	-
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	-	-	-
18					
19	Operating income	L4 - L17	$ -	$ -	$ -
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies	NC-2401	(11,603)	9,641	(21,244)
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (11,603)	$ 9,641	$ (21,244)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust coal inventory
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2401
Supplemental
December Update

Line No.	Description	Total System		NC Retail Allocation		Total NC Retail
1						
2	Estimated full load burn - excluding retirements	32,017	[1]			
3	Target number of days inventory	35	[1]			
4	Target coal inventory balance at December 31, 2018 (L2 x L3)	1,120,595	*Tons*			
5	Projected average delivered coal costs per ton	$ 65.43	[2]			
6	Projected coal inventory balance (L4 x L5/1,000)	$ 73,321		61.1093%	[3]	$ 44,806
7	Adjust for Fixed Transportation Costs	13,977	[4]	61.1093%	[3]	8,541
8	Total coal inventory balance	$ 87,298				$ 53,347
9						
10	Actual coal inventory balance	$ 106,285	[5]	61.1093%	[3]	$ 64,950
11						
12	Impact to materials and supplies (coal inventory) (L8 - L10)	$ (18,987)				$ (11,603)

[1] E-1 Item 46E, Coal Consumption and Inventory Data adjusted to reflect the retirement of Asheville units
[2] NC-2402 - Docket No. E-2, Sub 1204, Direct Testimony of Brett Phipps
[3] NC Retail Allocation Factor - E1ALL
[4] Beginning in 2019, the average delivered costs/ton does not include fixed transportation costs. The delivered cost of fuel used is consistent with Docket No E-2, Sub 1204 with a projected period of 12/1/2019-11/30/2020.
=Target inventory balance in tons/estimated coal delivered in tons * Transportation Cost
[5] E-1 Item 2, Working Trial Balance - Accounts 0151130 and 0151131

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust coal inventory
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2402
Supplemental
December Update

Direct Testimony of Brett Phipps
Docket E-2, Sub 1204 Page 6 excerpt

Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. DEP's current coal burn projection for the billing period is 4.4 million tons, compared to 3.6 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $66.12 per ton for the billing period compared to $84.81 per ton in the test period. The lower projected cost is due, in part, to newly negotiated rail transportation contracts that went into effect March 1, 2019. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEP is able to consume; (3) performance of contract deliveries by suppliers and railroads which

DIRECT TESTIMONY OF BRETT PHIPPS
DUKE ENERGY PROGRESS, LLC
Page 6
Docket No. E-2, Sub 1204

Updated Testimony of Brett Phipps
Docket E-2, Sub 1204 Transcript excerpt

Q Mr. Phipps, will you please begin by stating your
full name and title for the record?
A My name is Brett Phipps. I'm the Managing
Director of fuel procurement.
Q Thank you. Mr. Phipps, did you prepare and cause
to be filed in this proceeding direct testimony
consisting of eight pages of testimony and three
exhibits?
A I did.
Q And, Mr. Phipps, do you have any changes to make
to your direct testimony at this time?
A I do. On page 6, line 18 of my testimony, the
value that's there of $66.12 should be updated to
reflect $65.43.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for credit card fees
For the test period ended December 31, 2018

NC-2500
Supplemental
February Update

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expenses for credit card fees costs by projecting 2019 transactions and applying a unit cost per transaction.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update:

NC-2503 - credit card transaction actuals updated through October 2019. The formula in line 18 has also been updated to account for 10 months of actuals vs 9 months of actuals.

November Update

An issue was identified with the previously reported 2019 actuals, therefore NC-2503 has been updated with revised actuals through November 2019. The formula in line 18 has also been updated to account for 11 months of actuals vs 10 months of actuals.

December update:

NC-2503 - credit card transaction actuals update through December 2019. The formula in line 18 has also been updated to account for 12 months of actuals.

January update:

NC-2503 - credit card transaction actuals update through January 2020. Line 18 reflects 13 months average times 12 months; Updated schedule titles to reflect actuals

February update:

NC-2503 - credit card transaction actuals update through February 2020. Line 18 reflects 14 months average times 12 months

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for credit card fees
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2500
Supplemental
February Update

Line No.	Description	Source	February	Total NC Retail Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-2501	5,307	5,197	110
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2501	(1,230)	(1,204)	(26)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	4,078	3,993	85
18					
19	Operating income	L4 - L17	$ (4,078)	$ (3,993)	$ (85)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for credit card fees
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2501
Supplemental
February Update

Line No.	Description	Total NC Retail	
1	Impact to Income Statement Line Items		
2	Projected NC costs		
3	Credit card fees	$ 5,307	[1]
4			
5	Impact to O&M (L3 + L4)	$ 5,307	
6			
7	Statutory tax rate	23.1693%	[2]
8	Impact to income taxes (-L5 x L7)	$ (1,230)	
9			
10	Impact to operating income (-L5 - L8)	$ (4,078)	
11			
12			
13	Impact to Rate Base Line Items		
14	Accumulated depreciation and amortization:		
15	Impact to accumulated depreciation	$ -	
16			
17	Working capital investment:		
18		$ -	
19			
20	Impact to working capital investment (L18)	$ -	
21			
22	Deferred tax rate	23.1693%	
23	Impact to accumulated deferred income tax (-L20 x L22)	$ -	
24			
25	Impact to rate base (L15 + L20 + L23)	$ -	

[1] NC-2502 - Duke Energy Progress - Projected credit card fees - NC Retail
[2] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC NC-2502
Docket No. E-2, Sub 1219 Supplemental
Adjust for credit card fees February Update
For the test period ended December 31, 2018

Duke Energy Progress - Projected credit card fees - NC Retail

Line No.		Transactions NC Residential		Cost per transaction		NC Residential Projected costs
1						
2	Annualized Transactions	3,538,318	[1]	$ 1.50	[2]	5,307,477
3	Total					$ 5,307,477

[1] NC-2503 - Annualized Credit/debit card and ACH transactions - NC Residential Only
[2] Contracted 3rd party fee

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for credit card fees
For the test period ended December 31, 2018

NC-2503
Supplemental
February Update

Annualized credit/debit card and ACH transactions - NC Residential Only

Line No.	Description	Total NC Retail	
1	Actual NC Residential Transactions:		
2	Jan 2019	$ 276,317	
3	Feb 2019	273,538	
4	Mar 2019	293,409	
5	Apr 2019	297,519	
6	May 2019	289,174	
7	Jun 2019	267,588	
8	Jul 2019	310,976	
9	Aug 2019	293,713	
10	Sep 2019	301,097	
11	Oct 2019	314,811	
12	Nov 2019	278,484	
13	Dec 2019	321,327	
14	Jan 2020	320,258	
15	Feb 2020	289,827	
16	Total NC Residential Transactions (L2 through L15)	4,128,038	[1]
17			
18	Annualized Transactions based on 14 months Actuals	3,538,318	

[1] Number of transactions provided by Revenue Services

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2600
Supplemental
January Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts depreciation expense and the reserve for depreciation to reflect the updated depreciation rates resulting from a new depreciation study.

January Update

Revised NC-2603 for change in treatment of Catalyst Depreciation

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2600
Supplemental
January Update

Line No.	Description	Source	Total NC Retail January	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power and net interchange		-	-	-
10	Wages, benefits, materials, etc.		-	-	-
11	Depreciation and amortization	NC-2601	88,728	89,601	(873)
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2601	(20,558)	(20,760)	202
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	68,170	68,841	(671)
18					
19	Operating income	L4 - L17	$ (68,170)	$ (68,841)	$ 671
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization	NC-2601	(88,728)	(88,728)	-
30	Electric plant in service, net	Sum L28 through L29	(88,728)	(88,728)	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment				
35	Plant held for future use		-	-	-
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40	Customer deposits		-	-	-
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (88,728)	$ (88,728)	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2601
Supplemental
January Update

Line No.	Description		Total System		NC Retail Allocation		Total NC Retail	
1	Change in Depreciation and amortization (See NC-2602)							
2	Production	$	126,087	[1]	61.5278% [2]	$	77,579	
3	Transmission		8,514	[1]	59.6699% [3]		5,081	
4	Distribution		(4,241)	[1]	87.1486% [4]		(3,696)	
5	Distribution COR Adjustment-Direct Assigned		-	[1]	100.0000%		-	
6	General		3,644	[1]	74.0412% [5]		2,698	
7	General Plant Amortization		9,544	[1]	74.0412% [5]		7,067	
8	Impact to depreciation and amortization (Sum L2 through L7)	$	143,549			$	88,728	
9								
10	Adjust to deprec. and amort. for costs recovered in riders	$	-	[7]	61.5278% [2]	$	-	
11								
12	Impact to depreciation and amortization (L8 + L10)	$	143,549			$	88,728	
13								
14	Statutory tax rate		23.1693%	[6]			23.1693%	[6]
15								
16	Impact to income taxes (-L12 x L14)	$	(33,259)			$	(20,558)	
17								
18	Impact to operating income (- L12 - L16)	$	(110,290)			$	(68,170)	
19								
20	Depreciation Reserve Adjustment							
21	Production	$	(126,087)		61.5278% [2]	$	(77,579)	
22	Transmission		(8,514)		59.6699% [3]		(5,081)	
23	Distribution		4,241		87.1486% [4]		3,696	
24	Distribution COR Adjustment-Direct Assigned		-		100.0000%		-	
25	General		(3,644)		74.0412% [5]		(2,698)	
26	General Plant Amortization		(9,544)		74.0412% [5]		(7,067)	
27	Impact to Depreciation reserve (Sum L21 through L26)	$	(143,549)			$	(88,728)	

[1] NC-2602 - Comparison of Current and Proposed Depreciation as of December 31, 2018
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - DTALL
[4] NC Retail Allocation Factor - RB PLT O DI
[5] NC Retail Allocation Factor - RB PLT O GN
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] In the supplemental January update, DEP is proposing to no longer flow cataylst depreciation expense through the fuel rider, therefore the adjustment from NC-2603 is no longer needed.

I/A

Smith
Supplemental Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2602
Supplemental
January Update

DUKE ENERGY PROGRESS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS
AS OF DECEMBER 31, 2018

		CURRENT					PROPOSED					
ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT	INCREASE/ (DECREASE)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
STEAM PRODUCTION PLANT												
311.00 STRUCTURES AND IMPROVEMENTS												
ASHEVILLE UNIT 1	42,616,358.21	12-2027	100-R2.5 *	(4)	0.95	404,855	12-2027	100-R2.5 *	(4)	1.35	573,609	168,754
ASHEVILLE UNIT 2	42,579,071.25	12-2027	100-R2.5 *	(4)	3.13	1,332,725	12-2027	100-R2.5 *	(4)	3.46	1,473,445	140,720
MAYO UNIT 1	170,239,859.39	06-2035	100-R2.5 *	(6)	1.95	3,319,677	06-2029	100-R2.5 *	(4)	2.87	4,879,145	1,559,468
ROXBORO UNIT 1	17,139,904.05	06-2028	100-R2.5 *	(6)	2.52	431,926	06-2028	100-R2.5 *	(5)	2.39	408,845	(23,081)
ROXBORO UNIT 2	5,512,432.01	06-2028	100-R2.5 *	(6)	3.42	188,525	06-2028	100-R2.5 *	(5)	3.57	196,628	8,103
ROXBORO UNIT 3	37,367,402.39	06-2033	100-R2.5 *	(6)	0.87	325,096	06-2029	100-R2.5 *	(5)	1.00	372,911	47,815
ROXBORO UNIT 4	19,539,071.49	06-2033	100-R2.5 *	(6)	3.60	703,407	06-2029	100-R2.5 *	(5)	5.37	1,048,303	344,896
ROXBORO COMMON	193,990,592.95	06-2033	100-R2.5 *	(6)	5.03	9,757,727	06-2029	100-R2.5 *	(5)	7.59	14,718,151	4,960,424
TOTAL STRUCTURES AND IMPROVEMENTS	528,984,691.74				3.11	16,463,938				4.47	23,671,037	7,207,099
312.00 BOILER PLANT EQUIPMENT												
ASHEVILLE UNIT 1	149,655,719.36	12-2027	60-R1 *	(4)	4.19	6,270,575	12-2027	60-R1 *	(4)	4.76	7,121,696	851,121
ASHEVILLE UNIT 2	145,625,344.87	12-2027	60-R1 *	(4)	2.94	4,281,385	12-2027	60-R1 *	(4)	3.22	4,682,918	401,533
MAYO UNIT 1	832,479,002.87	06-2035	60-R1 *	(6)	4.02	33,465,656	06-2029	60-R1 *	(4)	6.06	50,461,597	16,995,941
ROXBORO UNIT 1	212,902,505.83	06-2028	60-R1 *	(6)	6.56	13,966,404	06-2028	60-R1 *	(5)	6.95	14,793,592	827,188
ROXBORO UNIT 2	309,506,429.33	06-2028	60-R1 *	(6)	5.04	15,599,124	06-2028	60-R1 *	(5)	5.50	17,017,838	1,418,714
ROXBORO UNIT 3	333,830,832.31	06-2033	60-R1 *	(6)	4.74	15,823,581	06-2029	60-R1 *	(5)	6.87	22,920,294	7,096,713
ROXBORO UNIT 4	404,141,708.49	06-2033	60-R1 *	(6)	1.33	5,375,085	06-2029	60-R1 *	(5)	3.61	14,572,511	9,197,426
ROXBORO COMMON	320,174,907.77	06-2033	60-R1 *	(6)	1.91	6,115,341	06-2029	60-R1 *	(5)	5.13	16,435,758	10,320,417
TOTAL BOILER PLANT EQUIPMENT	2,708,316,450.83				3.73	100,897,151				5.46	148,006,204	47,109,053
312.10 BOILER PLANT EQUIPMENT - SCR CATALYST												
ASHEVILLE UNIT 1	3,957,262.78	12-2027	10-S2 *	0	4.47	176,890	12-2027	10-S1 *	0	-	0	(176,890)
ASHEVILLE UNIT 2	1,798,265.75	12-2027	10-S2 *	0	5.44	97,826	12-2027	10-S1 *	0	-	0	(97,826)
MAYO UNIT 1	7,428,602.62	06-2035	10-S2 *	0	5.49	407,830	06-2029	10-S1 *	0	-	0	(407,830)
ROXBORO UNIT 1	7,925,144.00	06-2028	10-S2 *	0	1.84	145,823	06-2028	10-S1 *	0	-	0	(145,823)
ROXBORO UNIT 2	5,857,261.54	06-2028	10-S2 *	0	3.91	229,019	06-2028	10-S1 *	0	-	0	(229,019)
ROXBORO UNIT 3	6,541,925.15	06-2033	10-S2 *	0	7.92	518,120	06-2029	10-S1 *	0	3.75	245,298	(272,822)
ROXBORO UNIT 4	7,261,916.42	06-2033	10-S2 *	0	1.22	88,595	06-2029	10-S1 *	0	-	0	(88,595)
TOTAL BOILER PLANT EQUIPMENT - SCR CATALYST	40,770,378.26				4.08	1,664,103				0.60	245,298	(1,418,805)
314.00 TURBOGENERATOR UNITS												
ASHEVILLE UNIT 1	18,830,227.72	12-2027	60-S0 *	(4)	6.65	1,252,210	12-2027	60-S0 *	(4)	7.32	1,378,245	126,035
ASHEVILLE UNIT 2	13,968,640.50	12-2027	60-S0 *	(4)	1.12	156,449	12-2027	60-S0 *	(4)	1.12	155,826	(623)
MAYO UNIT 1	109,608,959.00	06-2035	60-S0 *	(6)	3.04	3,332,112	06-2029	60-S0 *	(4)	4.44	4,863,907	1,531,795
ROXBORO UNIT 1	45,628,567.76	06-2028	60-S0 *	(6)	6.66	3,038,863	06-2028	60-S0 *	(5)	6.91	3,153,178	114,315
ROXBORO UNIT 2	44,959,643.18	06-2028	60-S0 *	(6)	7.10	3,192,135	06-2028	60-S0 *	(5)	7.60	3,418,913	226,778
ROXBORO UNIT 3	73,030,422.44	06-2033	60-S0 *	(6)	4.39	3,206,036	06-2029	60-S0 *	(5)	6.30	4,601,862	1,395,826
ROXBORO UNIT 4	69,565,691.07	06-2033	60-S0 *	(6)	3.26	2,267,842	06-2029	60-S0 *	(5)	5.35	3,723,176	1,455,334
ROXBORO COMMON	458,890.76	06-2033	60-S0 *	(6)	2.36	10,830	06-2029	60-S0 *	(5)	3.14	14,425	3,595
TOTAL TURBOGENERATOR UNITS	376,051,042.43				4.38	16,456,475				5.67	21,309,532	4,853,057
315.00 ACCESSORY ELECTRIC EQUIPMENT												
ASHEVILLE UNIT 1	17,304,563.70	12-2027	65-R1.5 *	(4)	4.75	821,967	12-2027	70-R1 *	(4)	5.18	896,804	74,837
ASHEVILLE UNIT 2	10,774,312.04	12-2027	65-R1.5 *	(4)	0.00	0	12-2027	70-R1 *	(4)	-	0	
MAYO UNIT 1	66,829,604.18	06-2035	65-R1.5 *	(6)	3.55	2,372,451	06-2029	70-R1 *	(4)	5.40	3,607,025	1,234,574
ROXBORO UNIT 1	27,911,638.64	06-2028	65-R1.5 *	(6)	7.40	2,065,461	06-2028	70-R1 *	(5)	7.71	2,151,100	85,639
ROXBORO UNIT 2	24,223,049.38	06-2028	65-R1.5 *	(6)	3.55	859,918	06-2028	70-R1 *	(5)	3.65	883,710	23,792
ROXBORO UNIT 3	42,579,385.55	06-2033	65-R1.5 *	(6)	4.61	1,962,910	06-2029	70-R1 *	(5)	6.84	2,913,552	950,642
ROXBORO UNIT 4	43,547,824.88	06-2033	65-R1.5 *	(6)	3.05	1,328,209	06-2029	70-R1 *	(5)	5.71	2,486,371	1,158,162
ROXBORO COMMON	23,722,266.18	06-2033	65-R1.5 *	(6)	5.01	1,188,486	06-2029	70-R1 *	(5)	7.27	1,723,633	535,147
TOTAL ACCESSORY ELECTRIC EQUIPMENT	256,892,644.55				4.13	10,599,401				5.71	14,662,195	4,062,794
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT												
ASHEVILLE UNIT 1	10,334,480.63	12-2027	50-S0 *	(4)	6.45	666,574	12-2027	45-S0 *	(4)	6.73	695,241	28,667
ASHEVILLE UNIT 2	5,120,201.92	12-2027	50-S0 *	(4)	1.74	89,092	12-2027	45-S0 *	(4)	1.79	91,397	2,305
MAYO UNIT 1	13,338,741.21	06-2035	50-S0 *	(6)	3.89	518,877	06-2029	45-S0 *	(4)	6.30	840,910	322,033
ROXBORO UNIT 1	4,072,524.77	06-2028	50-S0 *	(6)	6.19	252,089	06-2028	45-S0 *	(5)	6.91	281,244	29,155
ROXBORO UNIT 2	4,425,440.03	06-2028	50-S0 *	(6)	3.85	170,379	06-2028	45-S0 *	(5)	4.84	214,299	43,920
ROXBORO UNIT 3	4,581,632.45	06-2033	50-S0 *	(6)	4.18	191,512	06-2029	45-S0 *	(5)	5.90	270,285	78,773
ROXBORO UNIT 4	5,430,383.41	06-2033	50-S0 *	(6)	3.83	207,984	06-2029	45-S0 *	(5)	5.68	308,691	100,707
ROXBORO COMMON	20,631,298.87	06-2033	50-S0 *	(6)	5.46	1,126,469	06-2029	45-S0 *	(5)	7.63	1,574,562	448,093
TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT	67,934,703.29				4.74	3,222,976				6.30	4,276,629	1,053,653
TOTAL STEAM PRODUCTION PLANT	**3,978,949,911.10**				**3.75**	**149,304,045**				**5.33**	**212,170,895**	62,866,850

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2602
Supplemental
January Update

DUKE ENERGY PROGRESS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS
AS OF DECEMBER 31, 2018

	ACCOUNT (1)	ORIGINAL COST AS OF DECEMBER 31, 2018 (2)	CURRENT PROBABLE RETIREMENT DATE (3)	CURRENT SURVIVOR CURVE (4)	CURRENT NET SALVAGE PERCENT (5)	CURRENT ANNUAL ACCRUAL RATE (6)	CURRENT ANNUAL ACCRUAL AMOUNT (7)	PROPOSED PROBABLE RETIREMENT DATE (8)	PROPOSED SURVIVOR CURVE (9)	PROPOSED NET SALVAGE PERCENT (10)	PROPOSED ANNUAL ACCRUAL RATE (11)	PROPOSED ANNUAL ACCRUAL AMOUNT (12)	INCREASE/ (DECREASE) (13)
	NUCLEAR PRODUCTION PLANT												
321.00	STRUCTURES AND IMPROVEMENTS												
	BRUNSWICK UNIT 1	423,009,418.66	09-2036	80-S1 *	(2)	2.62	11,082,847	09-2036	75-S1 *	(1)	3.35	14,175,485	3,092,638
	BRUNSWICK UNIT 2	397,968,469.79	12-2034	80-S1 *	(2)	2.64	10,506,368	12-2034	75-S1 *	(1)	2.89	11,520,013	1,013,645
	HARRIS UNIT 1	1,996,266,873.69	10-2046	80-S1 *	(3)	1.64	32,738,777	10-2046	75-S1 *	(2)	1.62	32,248,496	(490,281)
	HARRIS DISALLOWANCE	(105,862,561.00)				1.29	(1,365,503)				1.29	(1,369,567)	(4,065)
	ROBINSON UNIT 2	373,649,660.90	07-2030	80-S1 *	(1)	3.40	12,704,088	07-2030	75-S1 *	(1)	4.37	16,338,445	3,634,357
	TOTAL STRUCTURES AND IMPROVEMENTS	3,085,031,862.04				2.13	65,666,577				2.36	72,912,872	7,246,295
322.00	REACTOR PLANT EQUIPMENT												
	BRUNSWICK UNIT 1	612,117,283.68	09-2036	55-R1.5 *	(2)	2.80	17,139,284	09-2036	52-R2 *	(1)	3.16	19,312,794	2,173,510
	BRUNSWICK UNIT 2	544,476,825.16	12-2034	55-R1.5 *	(2)	2.87	15,626,485	12-2034	52-R2 *	(1)	3.14	17,115,022	1,488,537
	HARRIS UNIT 1	1,075,559,612.15	10-2046	55-R1.5 *	(3)	2.73	29,362,777	10-2046	52-R2 *	(2)	2.68	28,850,918	(511,859)
	HARRIS DISALLOWANCE	(132,409,445.00)				1.29	(1,707,926)				1.29	(1,713,010)	(5,084)
	ROBINSON UNIT 2	462,756,240.49	07-2030	55-R1.5 *	(1)	3.40	15,733,712	07-2030	52-R2 *	(1)	4.21	19,464,027	3,730,315
	TOTAL REACTOR PLANT EQUIPMENT	2,562,500,516.48				2.97	76,154,332				3.24	83,029,751	6,875,418
323.00	TURBOGENERATOR UNITS												
	BRUNSWICK UNIT 1	285,997,062.33	09-2036	50-S0 *	(2)	3.06	8,751,510	09-2036	40-S0 *	(1)	4.13	11,823,008	3,071,498
	BRUNSWICK UNIT 2	172,548,284.27	12-2034	50-S0 *	(2)	3.32	5,728,603	12-2034	40-S0 *	(1)	3.73	6,442,418	713,815
	HARRIS UNIT 1	535,687,360.49	10-2046	50-S0 *	(3)	2.48	13,285,047	10-2046	40-S0 *	(2)	3.24	17,371,808	4,086,761
	HARRIS DISALLOWANCE	(610,466.00)				1.29	(7,874)				1.29	(7,898)	(23)
	ROBINSON UNIT 2	333,276,803.83	07-2030	50-S0 *	(1)	5.04	16,797,151	07-2030	40-S0 *	(1)	8.07	26,899,155	10,102,004
	TOTAL TURBOGENERATOR UNITS	1,326,899,044.92				3.36	44,554,436				4.71	62,528,491	17,974,055
324.00	ACCESSORY ELECTRIC EQUIPMENT												
	BRUNSWICK UNIT 1	161,647,774.74	09-2036	55-R2.5 *	(2)	3.77	6,094,121	09-2036	50-R2.5 *	(1)	4.22	6,821,086	726,965
	BRUNSWICK UNIT 2	210,342,927.28	12-2034	55-R2.5 *	(2)	3.20	6,730,974	12-2034	50-R2.5 *	(1)	4.01	8,431,189	1,700,215
	HARRIS UNIT 1	820,436,969.84	10-2046	55-R2.5 *	(3)	1.86	15,260,128	10-2046	50-R2.5 *	(2)	1.99	16,303,928	1,043,800
	HARRIS DISALLOWANCE	(256,837,664.66)				1.29	(3,312,904)				1.29	(3,322,766)	(9,862)
	ROBINSON UNIT 2	279,070,966.07	07-2030	55-R2.5 *	(1)	3.84	10,716,325	07-2030	50-R2.5 *	(1)	6.43	17,942,656	7,226,331
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	1,214,660,973.27				2.92	35,488,644				3.80	46,176,093	10,687,450
325.00	MISCELLANEOUS PLANT EQUIPMENT												
	BRUNSWICK UNIT 1	201,192,590.16	09-2036	50-R1 *	(2)	3.56	7,162,456	09-2036	50-R1.5 *	(1)	3.91	7,865,762	703,306
	BRUNSWICK UNIT 2	68,906,220.33	12-2034	50-R1 *	(2)	3.52	2,425,499	12-2034	50-R1.5 *	(1)	3.68	2,534,043	108,544
	HARRIS UNIT 1	247,301,101.58	10-2046	50-R1 *	(3)	2.36	5,836,306	10-2046	50-R1.5 *	(2)	2.38	5,889,127	52,821
	HARRIS DISALLOWANCE	(55,577,154.00)				1.29	(716,880)				1.29	(719,014)	(2,134)
	ROBINSON UNIT 2	190,043,010.80	07-2030	50-R1 *	(1)	5.61	10,661,413	07-2030	50-R1.5 *	(1)	6.34	12,040,133	1,378,720
	TOTAL MISCELLANEOUS PLANT EQUIPMENT	651,865,768.87				3.89	25,368,794				4.24	27,610,051	2,241,257
	TOTAL NUCLEAR PRODUCTION PLANT	**8,840,958,165.58**				**2.80**	**247,232,783**				**3.31**	**292,257,258**	45,024,474
	HYDRAULIC PRODUCTION PLANT												
331.00	STRUCTURES AND IMPROVEMENTS												
	BLEWETT	6,620,300.84	06-2055	110-R2 *	(41)	2.59	171,466	06-2055	110-R2 *	(33)	2.83	187,401	15,935
	MARSHALL	1,523,286.57	06-2035	110-R2 *	(16)	6.77	103,127	06-2035	110-R2 *	(16)	7.03	107,146	4,019
	TILLERY	6,634,057.32	06-2055	110-R2 *	(33)	2.37	157,227	06-2055	110-R2 *	(29)	3.05	202,328	45,101
	WALTERS	3,472,324.03	06-2034	110-R2 *	(6)	3.15	109,378	06-2034	110-R2 *	(6)	3.24	112,577	3,199
	TOTAL STRUCTURES AND IMPROVEMENTS	18,249,968.76				2.97	541,198				3.34	609,452	68,254
332.00	RESERVOIRS, DAMS AND WATERWAY												
	BLEWETT	8,275,323.29	06-2055	120-R3 *	(41)	2.22	183,712	06-2055	120-R3 *	(33)	1.94	160,135	(23,577)
	MARSHALL	4,071,208.19	06-2035	120-R3 *	(16)	3.30	134,350	06-2035	120-R3 *	(16)	3.52	143,440	9,090
	TILLERY	6,796,645.31	06-2055	120-R3 *	(33)	1.82	123,699	06-2055	120-R3 *	(29)	1.62	110,074	(13,625)
	WALTERS	34,543,362.20	06-2034	120-R3 *	(6)	2.87	991,394	06-2034	120-R3 *	(6)	3.46	1,195,944	204,550
	TOTAL RESERVOIRS, DAMS AND WATERWAY	53,686,538.99				2.67	1,433,155				3.00	1,609,593	176,438
333.00	WATER WHEELS, TURBINES AND GENERATORS												
	BLEWETT	13,436,525.48	06-2055	70-R1.5 *	(41)	4.84	650,328	06-2055	75-R1.5 *	(33)	4.00	536,807	(113,521)
	MARSHALL	6,041,207.23	06-2035	70-R1.5 *	(16)	2.98	180,028	06-2035	75-R1.5 *	(16)	3.14	189,470	9,442
	TILLERY	14,142,264.87	06-2055	70-R1.5 *	(33)	3.86	545,891	06-2055	75-R1.5 *	(29)	3.75	530,595	(15,296)
	WALTERS	4,456,120.96	06-2034	70-R1.5 *	(6)	3.14	139,922	06-2034	75-R1.5 *	(6)	3.49	155,664	15,742
	TOTAL WATER WHEELS, TURBINES AND GENERATORS	38,076,118.54				3.98	1,516,169				3.71	1,412,536	(103,633)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2602
Supplemental
January Update

DUKE ENERGY PROGRESS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS
AS OF DECEMBER 31, 2018

			CURRENT					PROPOSED					
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT	INCREASE/ (DECREASE)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
334.00	ACCESSORY ELECTRIC EQUIPMENT												
	BLEWETT	7,543,722.48	06-2055	60-S1 *	(41)	3.81	287,416	06-2055	55-R1 *	(33)	4.49	338,949	51,533
	MARSHALL	1,179,515.99	06-2035	60-S1 *	(16)	3.44	40,575	06-2035	55-R1 *	(16)	3.41	40,208	(367)
	TILLERY	3,853,242.31	06-2055	60-S1 *	(33)	3.40	131,010	06-2055	55-R1 *	(29)	3.57	137,612	6,602
	WALTERS	13,242,973.33	06-2034	60-S1 *	(6)	5.62	744,255	06-2034	55-R1 *	(6)	6.47	856,757	112,502
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	25,819,454.11				4.66	1,203,257				5.32	1,373,526	170,269
335.00	MISCELLANEOUS PLANT EQUIPMENT												
	BLEWETT	1,826,329.58	06-2055	55-S0.5 *	(41)	3.77	68,853	06-2055	55-S0 *	(33)	3.66	66,903	(1,950)
	MARSHALL	200,696.66	06-2035	55-S0.5 *	(16)	5.23	10,496	06-2035	55-S0 *	(16)	5.44	10,921	425
	TILLERY	1,227,560.24	06-2055	55-S0.5 *	(33)	2.70	33,144	06-2055	55-S0 *	(29)	2.68	32,943	(201)
	WALTERS	1,756,787.00	06-2034	55-S0.5 *	(6)	4.83	84,853	06-2034	55-S0 *	(6)	5.51	96,765	11,912
	TOTAL MISCELLANEOUS PLANT EQUIPMENT	5,011,373.48				3.94	197,346				4.14	207,532	10,186
336.00	ROADS, RAILROADS, AND BRIDGES												
	MARSHALL	12,946.58	06-2035	75-R3 *	(16)	2.84	368	06-2035	75-R3 *	(16)	2.81	364	(4)
	WALTERS	8,258.48	06-2034	75-R3 *	(6)	0.52	43	06-2034	75-R3 *	(6)	0.29	24	(19)
	TOTAL ROADS, RAILROADS, AND BRIDGES	21,205.06				1.94	411				1.83	388	(23)
	TOTAL HYDRAULIC PRODUCTION PLANT	**140,864,658.94**				**3.47**	**4,891,536**				**3.70**	**5,213,027**	321,491
	OTHER PRODUCTION PLANT												
341.00	STRUCTURES AND IMPROVEMENTS												
	ASHEVILLE IC TURBINE	31,762,836.46	06-2039	50-S2 *	(3)	2.95	937,004	06-2039	50-S1 *	(3)	3.07	975,677	38,673
	BLEWETT IC TURBINES	979,562.66	06-2024	50-S2 *	(7)	1.36	13,322	06-2024	50-S1 *	(7)	1.14	11,136	(2,186)
	DARLINGTON IC TURBINE UNITS 1-11	362,282.66	06-2020	50-S2 *	(6)	0.00	0	06-2020	50-S1 *	(7)	-	0	0
	DARLINGTON IC TURBINE UNITS 12 AND 13	8,403,245.66	06-2037	50-S2 *	(6)	0.15	12,605	06-2037	50-S1 *	(7)	0.83	69,646	57,041
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	9,013,914.23	06-2040	50-S2 *	(4)	2.66	239,770	06-2040	50-S1 *	(4)	2.82	254,463	14,693
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	1,356,819.84	06-2049	50-S2 *	(4)	2.74	37,177	06-2049	50-S1 *	(4)	2.97	40,347	3,170
	SMITH IC TURBINES (RICHMOND COUNTY)	19,344,678.47	06-2041	50-S2 *	(2)	2.89	559,061	06-2041	50-S1 *	(2)	2.99	579,000	19,939
	SUTTON BLACKSTART	11,574,792.86	06-2017	50-S2 *	(20)	0.00	0	06-2057	50-S1 *	(9)	2.00	231,353	231,353
	WEATHERSPOON IC TURBINES	3,568,977.41	06-2024	50-S2 *	(20)	1.51	53,892	06-2024	50-S1 *	(21)	2.59	92,356	38,464
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	47,694,242.52	06-2042	50-S2 *	(3)	0.90	429,248	06-2042	50-S1 *	(4)	0.92	440,153	10,905
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	40,103,160.35	06-2051	50-S2 *	(7)	2.89	1,158,981	06-2051	50-S1 *	(8)	3.07	1,232,177	73,196
	SUTTON COMBINED CYCLE	13,462,878.60	06-2053	50-S2 *	(2)	3.54	476,586	06-2053	50-S1 *	(3)	3.81	512,673	36,087
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	25,476,302.18	06-2052	50-S2 *	(5)	2.38	606,336	06-2052	50-S1 *	(6)	2.79	711,705	105,369
	TOTAL STRUCTURES AND IMPROVEMENTS	213,103,693.90				2.12	4,523,982				2.42	5,150,686	626,704
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR												
	CAMP LEJUNE	26,130.74	06-2040	25-S2.5 *	(8)	5.03	1,314	06-2040	30-S2.5 *	(9)	5.00	1,307	(7)
	FAYETTEVILLE	3,957.51	06-2040	25-S2.5 *	(10)	5.12	203	06-2040	30-S2.5 *	(11)	5.15	204	1
	ELM CITY	3,925.80	06-2041	25-S2.5 *	(15)	5.17	203	06-2041	30-S2.5 *	(15)	5.17	203	0
	TOTAL STRUCTURES AND IMPROVEMENTS - SOLAR	34,014.05				5.06	1,719.96				5.04	1,714	(6)
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES												
	ASHEVILLE IC TURBINE	5,115,723.34	06-2039	50-R2.5 *	(3)	2.25	115,104	06-2039	45-R2 *	(3)	2.90	148,602	33,498
	BLEWETT IC TURBINES	413,479.62	06-2024	50-R2.5 *	(7)	1.86	7,691	06-2024	45-R2 *	(7)	1.75	7,229	(462)
	DARLINGTON IC TURBINE UNITS 1-11	5,048,367.44	06-2020	50-R2.5 *	(6)	0.00	0	06-2020	45-R2 *	(7)	-	0	
	DARLINGTON IC TURBINE UNITS 12 AND 13	7,243,963.20	06-2037	50-R2.5 *	(6)	1.32	95,620	06-2037	45-R2 *	(7)	1.50	108,699	13,079
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	7,363,988.43	06-2040	50-R2.5 *	(4)	2.77	203,982	06-2040	45-R2 *	(4)	2.98	219,470	15,488
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	1,461,178.80	06-2049	50-R0.5 *	(4)	2.99	43,689	06-2049	45-R2 *	(4)	2.98	43,476	(213)
	SMITH IC TURBINES (RICHMOND COUNTY)	8,473,790.16	06-2041	50-R2.5 *	(2)	3.01	255,061	06-2041	45-R2 *	(2)	3.15	267,152	12,091
	SUTTON BLACKSTART	5,990,884.76				2.93	175,533	06-2057	45-R2 *	(9)	3.14	188,103	12,570
	WEATHERSPOON IC TURBINES	1,651,095.21	06-2024	50-R2.5 *	(20)	5.30	87,508	06-2024	45-R2 *	(21)	8.49	140,115	52,607
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	13,523,522.65	06-2042	50-R2.5 *	(3)	2.74	370,545	06-2042	45-R2 *	(4)	3.00	405,772	35,227
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	22,575,250.21	06-2051	50-R2.5 *	(7)	2.92	659,197	06-2051	45-R2 *	(8)	3.11	702,612	43,415
	SUTTON COMBINED CYCLE	19,656,537.55	06-2053	50-R2.5 *	(2)	2.93	575,937	06-2053	45-R2 *	(3)	4.25	835,790	259,853
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	25,423,310.37	06-2052	50-R2.5 *	(5)	3.07	780,496	06-2052	45-R2 *	(6)	3.33	845,788	65,292
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES	123,941,091.74				2.72	3,370,363				3.16	3,912,808	542,445

OFFICIAL COPY

Mar 13 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2602
Supplemental
January Update

DUKE ENERGY PROGRESS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS
AS OF DECEMBER 31, 2018

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	CURRENT PROBABLE RETIREMENT DATE	CURRENT SURVIVOR CURVE	CURRENT NET SALVAGE PERCENT	CURRENT ANNUAL ACCRUAL RATE	CURRENT ANNUAL ACCRUAL AMOUNT	PROPOSED PROBABLE RETIREMENT DATE	PROPOSED SURVIVOR CURVE	PROPOSED NET SALVAGE PERCENT	PROPOSED ANNUAL ACCRUAL RATE	PROPOSED ANNUAL ACCRUAL AMOUNT	INCREASE/ (DECREASE)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
343.00	PRIME MOVERS												
	ASHEVILLE IC TURBINE	51,871,873.24	06-2039	35-S0 *	(3)	3.18	1,649,526	06-2039	30-R0.5 *	(3)	5.08	2,634,563	985,037
	BLEWETT IC TURBINES	8,455,727.27	06-2024	35-S0 *	(7)	3.76	317,935	06-2024	30-R0.5 *	(7)	3.98	336,664	18,729
	DARLINGTON IC TURBINE UNITS 1-11	22,476,731.53	06-2020	35-S0 *	(6)	19.72	4,432,411	06-2020	30-R0.5 *	(7)	43.45	9,767,204	5,334,793
	DARLINGTON IC TURBINE UNITS 12 AND 13	39,502,461.61	06-2037	35-S0 *	(6)	5.32	2,101,531	06-2037	30-R0.5 *	(7)	7.34	2,901,267	799,736
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	121,712,253.32	06-2040	35-S0 *	(4)	3.82	4,649,408	06-2040	30-R0.5 *	(4)	3.89	4,737,903	88,495
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	61,526,436.54	06-2049	35-S0 *	(4)	3.46	2,128,815	06-2049	30-R0.5 *	(4)	3.78	2,326,209	197,394
	SMITH IC TURBINES (RICHMOND COUNTY)	230,437,633.01	06-2041	35-S0 *	(2)	5.46	12,581,895	06-2041	30-R0.5 *	(2)	6.46	14,883,340	2,301,445
	SUTTON BLACKSTART	65,019,558.96				3.56	2,314,696	06-2057	30-R0.5 *	(9)	4.08	2,651,182	336,486
	WEATHERSPOON IC TURBINES	12,638,464.88	06-2024	35-S0 *	(20)	0.19	24,013	06-2024	30-R0.5 *	(21)	0.68	86,525	62,512
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	114,272,116.59	06-2042	35-S0 *	(3)	5.72	6,536,365	06-2042	30-R0.5 *	(4)	7.04	8,046,676	1,510,311
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	236,173,460.30	06-2051	35-S0 *	(7)	3.84	9,069,061	06-2051	30-R0.5 *	(8)	3.96	9,344,070	275,009
	SUTTON COMBINED CYCLE	361,361,292.77	06-2053	35-S0 *	(2)	3.56	12,864,462	06-2053	30-R0.5 *	(3)	4.18	15,105,488	2,241,026
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	443,686,010.74	06-2052	35-S0 *	(5)	3.96	17,569,966	06-2052	30-R0.5 *	(6)	4.29	19,052,498	1,482,532
	TOTAL PRIME MOVERS	1,769,134,020.76				4.31	76,240,084				5.19	91,873,589	15,633,505
343.10	PRIME MOVERS - ROTABLE PARTS												
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	39,318,264.60	06-2042	5-L0.5 *	40	13.49	5,304,034	06-2042	6-L0.5 *	40	12.31	4,840,705	(463,329)
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	44,987,832.65	06-2051	5-L0.5 *	40	15.17	6,824,654	06-2051	6-L0.5 *	40	13.28	5,974,679	(849,975)
	SUTTON COMBINED CYCLE	29,483,115.01	06-2053	5-L0.5 *	40	14.68	4,328,121	06-2053	6-L0.5 *	40	12.14	3,577,906	(750,215)
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	56,542,095.59	06-2052	5-L0.5 *	40	14.68	8,300,380	06-2052	6-L0.5 *	40	12.48	7,057,740	(1,242,640)
	TOTAL PRIME MOVERS - ROTABLE PARTS	170,331,307.85				14.53	24,757,189				12.59	21,451,030	(3,306,159)
344.00	GENERATORS												
	ASHEVILLE IC TURBINE	7,769,953.49	06-2039	55-R2 *	(3)	2.83	219,890	06-2039	50-R2 *	(3)	3.01	233,653	13,763
	BLEWETT IC TURBINES	1,988,284.95	06-2024	55-R2 *	(7)	0.00	0	06-2024	50-R2 *	(7)	-	0	0
	DARLINGTON IC TURBINE UNITS 1-11	12,472,614.73	06-2020	55-R2 *	(6)	11.27	1,405,664	06-2020	50-R2 *	(7)	24.83	3,097,560	1,691,896
	DARLINGTON IC TURBINE UNITS 12 AND 13	17,131,838.45	06-2037	55-R2 *	(6)	3.92	671,568	06-2037	50-R2 *	(7)	4.29	735,468	63,900
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	22,068,501.33	06-2040	55-R2 *	(4)	2.90	639,987	06-2040	50-R2 *	(4)	2.87	632,402	(7,585)
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	13,021,303.33	06-2049	55-R2 *	(4)	2.85	371,107	06-2049	50-R2 *	(4)	3.00	390,823	19,716
	SMITH IC TURBINES (RICHMOND COUNTY)	37,046,160.65	06-2041	55-R2 *	(2)	5.43	2,011,607	06-2041	50-R2 *	(2)	10.08	3,735,595	1,723,988
	SUTTON BLACKSTART	2,145,710.72				2.88	61,796	06-2057	50-R2 *	(9)	2.77	59,357	(2,439)
	WEATHERSPOON IC TURBINES	2,095,743.68	06-2024	55-R2 *	(20)	0.00	0	06-2024	50-R2 *	(21)	-	0	0
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	40,449,074.75	06-2042	55-R2 *	(3)	1.07	432,805	06-2042	50-R2 *	(4)	-	0	(432,805)
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	31,516,637.44	06-2051	55-R2 *	(7)	2.90	913,982	06-2051	50-R2 *	(8)	3.00	946,600	32,618
	SUTTON COMBINED CYCLE	44,450,493.34	06-2053	55-R2 *	(2)	2.88	1,280,174	06-2053	50-R2 *	(3)	3.00	1,335,598	55,424
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	55,122,184.33	06-2052	55-R2 *	(5)	3.07	1,692,251	06-2052	50-R2 *	(6)	3.17	1,748,825	56,574
	TOTAL GENERATORS	287,278,501.19				3.38	9,700,831				4.50	12,915,881	3,215,050
344.20	GENERATORS - SOLAR												
	CAMP LEJUNE	15,956,191.94	06-2040	25-S2.5 *	(8)	5.03	802,596	06-2040	25-S2.5 *	(9)	5.15	822,344	19,748
	FAYETTEVILLE	32,469,234.56	06-2040	25-S2.5 *	(10)	5.12	1,662,425	06-2040	25-S2.5 *	(11)	5.26	1,708,709	46,284
	ELM CITY	51,863,631.58	06-2041	25-S2.5 *	(15)	5.17	2,681,350	06-2041	25-S2.5 *	(15)	5.27	2,731,170	49,820
	WARSAW	87,181,902.80	06-2040	25-S2.5 *	(11)	5.18	4,516,023	06-2040	25-S2.5 *	(12)	5.31	4,629,736	113,713
	TOTAL GENERATORS - SOLAR	187,470,960.88				5.15	9,662,394				5.28	9,891,959	229,565
345.00	ACCESSORY ELECTRIC EQUIPMENT												
	ASHEVILLE IC TURBINE	13,502,429.56	06-2039	50-R1.5 *	(3)	3.67	495,539	06-2039	50-R1.5 *	(3)	4.07	549,433	53,894
	BLEWETT IC TURBINES	1,418,891.29	06-2024	50-R1.5 *	(7)	1.18	16,743	06-2024	50-R1.5 *	(7)	0.88	12,494	(4,249)
	DARLINGTON IC TURBINE UNITS 1-11	4,869,111.48	06-2020	50-R1.5 *	(6)	7.99	389,042	06-2020	50-R1.5 *	(7)	8.43	410,605	21,563
	DARLINGTON IC TURBINE UNITS 12 AND 13	10,782,807.93	06-2037	50-R1.5 *	(6)	3.73	402,199	06-2037	50-R1.5 *	(7)	4.02	433,757	31,558
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	19,926,915.26	06-2040	50-R1.5 *	(4)	3.01	599,800	06-2040	50-R1.5 *	(4)	2.89	576,702	(23,098)
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	10,599,164.94	06-2049	50-R1.5 *	(4)	2.94	311,615	06-2049	50-R1.5 *	(4)	3.03	321,295	9,680
	SMITH IC TURBINES (RICHMOND COUNTY)	29,257,399.18	06-2041	50-R1.5 *	(2)	3.02	883,573	06-2041	50-R1.5 *	(2)	3.06	894,076	10,503
	SUTTON BLACKSTART	13,595,340.46				3.15	428,253	06-2057	50-R1.5 *	(9)	2.79	379,136	(49,117)
	WEATHERSPOON IC TURBINES	3,003,206.27	06-2024	50-R1.5 *	(20)	8.62	258,876	06-2024	50-R1.5 *	(21)	10.98	329,700	70,824
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	21,653,205.44	06-2042	50-R1.5 *	(3)	3.18	688,572	06-2042	50-R1.5 *	(4)	3.34	723,937	35,365
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	51,327,924.43	06-2051	50-R1.5 *	(7)	3.06	1,570,634	06-2051	50-R1.5 *	(8)	3.16	1,621,061	50,427
	SUTTON COMBINED CYCLE	62,940,670.78	06-2053	50-R1.5 *	(2)	3.15	1,982,631	06-2053	50-R1.5 *	(3)	3.20	2,012,729	30,098
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	76,581,369.69	06-2052	50-R1.5 *	(5)	3.25	2,488,895	06-2052	50-R1.5 *	(6)	3.31	2,531,320	42,425
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	319,458,436.71				3.29	10,516,374				3.38	10,796,245	279,871
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR												
	CAMP LEJUNE	2,761,117.30	06-2040	25-S2.5 *	(8)	5.01	138,332	06-2040	25-S2.5 *	(9)	5.13	141,616	3,284
	FAYETTEVILLE	533,260.74	06-2040	25-S2.5 *	(10)	5.13	27,356	06-2040	25-S2.5 *	(11)	5.26	28,033	677
	ELM CITY	133,458.18	06-2041	25-S2.5 *	(15)	5.17	6,900	06-2041	25-S2.5 *	(15)	5.24	6,990	90
	WARSAW	1,258,878.46	06-2040	25-S2.5 *	(11)	5.17	65,084	06-2040	25-S2.5 *	(12)	5.30	66,731	1,647
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR	4,686,714.68				5.07	237,672				5.19	243,370	5,698

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2602
Supplemental
January Update

DUKE ENERGY PROGRESS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS
AS OF DECEMBER 31, 2018

	ACCOUNT (1)	ORIGINAL COST AS OF DECEMBER 31, 2018 (2)	CURRENT PROBABLE RETIREMENT DATE (3)	CURRENT SURVIVOR CURVE (4)	CURRENT NET SALVAGE PERCENT (5)	CURRENT ANNUAL ACCRUAL RATE (6)	CURRENT ANNUAL ACCRUAL AMOUNT (7)	PROPOSED PROBABLE RETIREMENT DATE (8)	PROPOSED SURVIVOR CURVE (9)	PROPOSED NET SALVAGE PERCENT (10)	PROPOSED ANNUAL ACCRUAL RATE (11)	PROPOSED ANNUAL ACCRUAL AMOUNT (12)	INCREASE/ (DECREASE) (13)
346.00	MISCELLANEOUS PLANT EQUIPMENT												
	ASHEVILLE IC TURBINE	3.414.473.38	06-2039	40-S1.5 *	(3)	3.46	118.141	06-2039	30-S1 *	(3)	4.85	165.627	47.486
	BLEWETT IC TURBINES	204.914.55	06-2024	40-S1.5 *	(7)	10.82	22.172	06-2024	30-S1 *	(7)	12.97	26.575	4.403
	DARLINGTON IC TURBINE UNITS 1-11	90.349.83	06-2020	40-S1.5 *	(6)	0.40	361	06-2020	30-S1 *	(7)	196.63	177.654	177.293
	DARLINGTON IC TURBINE UNITS 12 AND 13	1,432,545.23	06-2037	40-S1.5 *	(6)	2.84	40,684	06-2037	30-S1 *	(7)	3.09	44,312	3,628
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	1,316,904.66	06-2040	40-S1.5 *	(4)	2.18	28,709	06-2040	30-S1 *	(4)	2.37	31,177	2,468
	H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14)	1,125,769.23	06-2049	40-S1.5 *	(4)	2.61	29,383	06-2049	30-S1 *	(4)	3.38	38,046	8,663
	SMITH IC TURBINES (RICHMOND COUNTY)	7,653,551.58	06-2041	40-S1.5 *	(2)	5.41	414,057	06-2041	30-S1 *	(2)	8.16	624,277	210,220
	SUTTON BLACKSTART	1,861,416.34				3.19	59,379	06-2057	30-S1 *	(9)	3.95	73,523	14,144
	WEATHERSPOON IC TURBINES	721,477.59	06-2024	40-S1.5 *	(20)	13.60	98,121	06-2024	30-S1 *	(21)	17.08	123,221	25,100
	SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY)	4,901,411.09	06-2042	40-S1.5 *	(3)	2.36	115,673	06-2042	30-S1 *	(4)	0.54	26,262	(89,411)
	SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY)	8,419,845.29	06-2051	40-S1.5 *	(7)	3.16	266,067	06-2051	30-S1 *	(8)	4.01	337,867	71,800
	SUTTON COMBINED CYCLE	8,363,725.23	06-2053	40-S1.5 *	(2)	3.19	266,803	06-2053	30-S1 *	(3)	4.01	335,284	68,481
	H.F. LEE COMBINED CYCLE (WAYNE COUNTY)	11,795,130.01	06-2052	40-S1.5 *	(5)	3.28	386,880	06-2052	30-S1 *	(6)	4.15	489,752	102,872
	TOTAL MISCELLANEOUS PLANT EQUIPMENT	51.301.514.01				3.60	1.846.430				4.86	2.493.577	647.147
346.20	MISCELLANEOUS PLANT EQUIPMENT - SOLAR												
	ELM CITY	10,069.36	06-2041	25-S2.5 *	(15)	5.17	521	06-2041	30-S2.5 *	(15)	5.24	528	7
	WARSAW	19,111.49	06-2040	25-S2.5 *	(11)	5.18	990	06-2040	30-S2.5 *	(12)	5.32	1,017	27
	TOTAL MISCELLANEOUS PLANT EQUIPMENT - SOLAR	29,180.85				5.18	1,511				5.29	1,545	34
	TOTAL OTHER PRODUCTION PLANT	**3,126,769,436.62**				**4.50**	**140,858,548**				**5.08**	**158,732,404**	17,873,856
	TOTAL PRODUCTION PLANT	**16,087,542,172.24**				**3.37**	**542,286,912**				**4.15**	**668,373,584**	126,086,671
	TRANSMISSION PLANT												
352.00	STRUCTURES AND IMPROVEMENTS	90,193,203.79		60-R3	(10)	1.78	1,605,439		60-R3	(10)	1.80	1,622,028	16,589
353.00	STATION EQUIPMENT	1,070,174,832.08		60-R1	(15)	1.90	20,333,322		55-R1.5	(15)	2.21	23,628,452	3,295,130
354.00	TOWERS AND FIXTURES	78,936,364.53		70-R4	(20)	1.35	1,065,641		75-R4	(20)	1.19	936,307	(129,334)
355.00	POLES AND FIXTURES	743,280,241.54		48-R1.5	(30)	2.22	16,500,821		49-R1.5	(40)	2.56	19,031,917	2,531,096
356.00	OVERHEAD CONDUCTORS AND DEVICES	551.039.389.11		70-R2	(30)	1.56	8.596.214		65-R2.5	(40)	2.07	11.383.033	2.786.819
357.00	UNDERGROUND CONDUIT	32.286.46		70-R3	(30)	2.30	743		60-R4	0	1.73	559	(184)
358.00	UNDERGROUND CONDUCTOR AND DEVICES	21.603.999.00		45-S2.5	0	2.30	496.892		45-S2.5	0	2.33	504.195	7.303
359.00	ROADS AND TRAILS	312.522.87		75-R3	0	1.37	4.282		75-R3	0	1.36	4.253	(29)
	TOTAL TRANSMISSION PLANT	**2,555,572,839.38**				**1.90**	**48,603,354**				**2.23**	**57,110,744**	8,507,390
	DISTRIBUTION PLANT												
361.00	STRUCTURES AND IMPROVEMENTS	127.079.158.04		60-R2	(15)	1.52	1.931.603		60-R2	(15)	1.59	2.021.366	89.763
362.00	STATION EQUIPMENT	683,055,387.27		46-R1	(15)	2.33	15,915,191		48-R1	(15)	2.24	15,332,138	(583,053)
364.00	POLES, TOWERS AND FIXTURES	855,785,431.01		45-R2.5	(100)	3.95	33,803,525		45-R2.5	(100)	3.92	33,556,194	(247,331)
365.00	OVERHEAD CONDUCTORS AND DEVICES	1,208,423,459.24		44-R1.5	(30)	2.15	25,981,104		45-R1	(30)	2.06	24,922,045	(1,059,059)
366.00	UNDERGROUND CONDUIT	199,779,066.87		45-S2.5	(10)	2.26	4,515,007		46-S2.5	(15)	2.37	4,725,775	210,768
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1,134,635,170.25		40-S2	(5)	1.76	19,969,579		42-S2	(5)	1.62	18,411,036	(1,558,543)
368.00	LINE TRANSFORMERS	1,131,254,323.64		39-R2	(5)	2.54	28,733,860		40-R2	(5)	2.46	27,806,592	(927,268)
369.00	SERVICES	681,775,180.43		42-R3	(10)	1.96	13,362,794		55-R3	(20)	1.59	10,868,784	(2,494,010)
370.00	METERS	51,889,323.64		30-R4	(15)	3.41	1,769,426		28-R4	(10)	1.91	1,063,840	(705,586)
370.01	METERS BEING REPLACED	142,517,522.33		30-R4	(5)		7,479,748		28-R4	(5)	**	7,007,351	(472,397)
370.02	METERS - UOF	69,710,613.08		17-S2.5	0	6.41	4,468,450		15-S2.5	0	5.64	4,645,856	177,406
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	318,551,648.97		25-L1.5	(10)	1.15	3,663,344		26-S0.5	(10)	1.38	4,405,748	742,404
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	264,812,433.62		30-R1	(10)	3.87	10,248,241		25-R1	(10)	4.85	12,840,929	2,592,688
	TOTAL DISTRIBUTION PLANT	**6,869,268,718.39**				**2.50**	**171,841,871**				**2.44**	**167,607,654**	(4,234,217)
	Distribution without AMR meters	6,726,751,196				**2.44**	164,362,123				**2.39**	160,600,303	
	GENERAL PLANT												
390.00	STRUCTURES AND IMPROVEMENTS	156,446,136.21		45-R1.5	(5)	2.42	3,785,996		45-R1.5	(5)	2.43	3,805,402	19,406
391.00	OFFICE FURNITURE AND EQUIPMENT												
	FULLY ACCRUED	10,200,214.55		20-SQ	0	0.00	0		FULLY ACCRUED		-	0	0
	AMORTIZED	14,520,609.30		20-SQ	0	5.00	726,030		15-SQ	0	6.67	968,950	242,920
	TOTAL OFFICE FURNITURE AND EQUIPMENT	24,720,823.85				2.94	726,030				3.92	968,950	242,920
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP	61,586,228.38		8-SQ	0	12.50	7,698,279		8-SQ	0	12.50	7,696,591	(1,688)
392.00	TRANSPORTATION EQUIPMENT	69,975,818.26		11-L2	10	10.29	7,200,512		11-L2	15	6.42	4,493,909	(2,706,603)
393.00	STORES EQUIPMENT	2,059,932.97		20-SQ	0	5.00	102,997		20-SQ	0	5.00	102,894	(103)
394.00	TOOLS,SHOPS AND GARAGE EQUIPMENT	90,247,659.07		20-SQ	0	5.00	4,512,383		20-SQ	0	5.00	4,508,503	(3,880)
395.00	LABORATORY EQUIPMENT	6,739,788.51		15-SQ	0	6.67	449,544		15-SQ	0	6.67	449,309	(235)
396.00	POWER OPERATED EQUIPMENT	5,679,686.30		12-S6	0	5.99	340,213		12-S6	0	7.26	412,343	72,130
397.00	COMMUNICATION EQUIPMENT												
	FULLY ACCRUED	59,435,956.41		20-SQ	0	-	0		FULLY ACCRUED		-	0	0
	AMORTIZED	120,535,862.75		20-SQ	0	5.00	6,026,793		10-SQ	0	10.00	12,049,716	6,022,923
	TOTAL COMMUNICATION EQUIPMENT	179,971,819.16					6,026,793				6.70	12,049,716	6,022,923
398.00	MISCELLANEOUS EQUIPMENT	23,040,257.68		20-SQ	0	5.00	1,152,013		20-SQ	0	5.00	1,150,868	(1,145)
	TOTAL GENERAL PLANT	**620,468,150.39**				**5.16**	**31,994,760**				**5.74**	**35,638,485**	3,643,725
	TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT	**10,045,309,708.16**				**2.51**	**252,439,985**				**2.59**	**260,356,883**	7,916,898

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2602
Supplemental
January Update

DUKE ENERGY PROGRESS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS
AS OF DECEMBER 31, 2018

			CURRENT					PROPOSED					
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT	INCREASE/ (DECREASE)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	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	06-2035	100-R4 *	0	0.78	27,902	06-2029	100-R4 *	0	0.97	34,725	6,823
	ROXBORO UNIT 1	1,827,202.76	06-2028	100-R4 *	0	-	0	06-2026	100-R4 *	0	-	0	0
	ROXBORO UNIT 3	3,037,934.25	06-2033	100-R4 *	0	-	0	06-2029	100-R4 *	0	-	0	0
	TOTAL ACCOUNT 310	9,361,456.50				0.30	27,902				0.37	34,725	6,823
320.00	LAND RIGHTS												
	HARRIS UNIT 1	49,809,293.03	10-2046	100-R4 *	0	1.21	602,692	10-2046	100-R4 *	0	1.21	601,134	(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				1.20	602,692				1.20	601,134	(1,558)
320.10	RIGHTS OF WAY												
	BRUNSWICK UNIT 1	9,724.11	09-2036	100-R4 *	0	0.89	87	09-2036	100-R4 *	0	0.93	90	3
	BRUNSWICK UNIT 2	51,363.07	12-2034	100-R4 *	0	0.17	87	12-2034	100-R4 *	0	0.17	88	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				0.26	174				0.26	178	4
	TOTAL ACCOUNT 320	50,192,441.05				1.20	602,866				1.20	601,312	(1,554)
330.00	LAND RIGHTS												
	WALTERS	80,796.94	06-2034	110-R4 *	0	2.73	2,206	06-2034	110-R4 *	0	2.67	2,160	(46)
330.10	RIGHTS OF WAY												
	BLEWETT	9,598.14	06-2055	110-R4 *	0	2.22	213	06-2055	110-R4 *	0	2.03	195	(18)
	MARSHALL	3,728.53	06-2035	110-R4 *	0	2.82	105	06-2035	110-R4 *	0	2.63	98	(7)
	TILLERY	19,764.49	06-2055	110-R4 *	0	1.41	279	06-2055	110-R4 *	0	1.32	261	(18)
	WALTERS	33,333.15	06-2034	110-R4 *	0	2.71	903	06-2034	110-R4 *	0	2.66	887	(16)
	TOTAL RIGHTS OF WAY	66,424.31				2.26	1,500				2.17	1,441	(59)
	TOTAL ACCOUNT 330	147,221.25				2.52	3,706				2.45	3,601	(105)
340.00	LAND RIGHTS												
	H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13)	2,048,655.08	06-2040	60-R4 *	0	2.51	51,421	06-2040	60-R4 *	0	2.40	49,114	(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	2.76	69,893	06-2040	60-R4 *	0	2.67	67,739	(2,154)
	TOTAL ACCOUNT 340	4,581,022.35				2.65	121,315				2.55	116,853	(4,462)
350.10	RIGHTS OF WAY	176,749,823.75		75-R3	0	1.15	2,032,623		75-R3	0	1.15	2,039,608	6,985
360.00	LAND RIGHTS	107,521.37		65-R3	0	1.49	1,602		65-R3	0	1.48	1,586	(16)
360.10	RIGHTS OF WAY	23,908,367.28		65-R3	0	1.28	306,027		65-R3	0	1.25	298,919	(7,108)
389.10	RIGHTS OF WAY	51,783.33		60-R3	0	51.51	26,674		60-R3	0	52.42	27,147	473
	TOTAL DEPRECIABLE LAND RIGHTS	**265,099,636.88**				1.18	**3,122,714**				**1.18**	**3,123,751**	1,037
	TOTAL ELECTRIC PLANT	**26,397,951,517.28**				3.02	**797,849,611**				**3.53**	**931,854,218**	134,004,606
	RESERVE ADJUSTMENT FOR AMORTIZATION												
391.00	OFFICE FURNITURE AND EQUIPMENT						2,640,179					3,426,096	785,917
393.00	STORES EQUIPMENT						172,193					152,417	(19,776)
394.00	TOOLS,SHOPS AND GARAGE EQUIPMENT						2,051,679					2,277,657	225,978
395.00	LABORATORY EQUIPMENT						(53,710)					(79,664)	(25,954)
397.00	COMMUNICATION EQUIPMENT						2,599,760					11,355,498	8,755,738
398.00	MISCELLANEOUS EQUIPMENT						1,574,923					1,397,290	(177,633)
	RESERVE ADJUSTMENT FOR AMORTIZATION						**8,985,024**					**18,529,294**	9,544,270
	TOTAL DEPRECIABLE ELECTRIC PLANT	**26,397,951,517.28**					**806,834,635**					**950,383,512**	143,548,876

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for new depreciation rates
For the test period ended December 31, 2018

NC-2603
Supplemental
January Update

Comparison of Current and Proposed Depreciation as of December 31, 2018 - Costs recovered through riders

Line No.	Description	CURRENT Calculated Annual Accrual [1]	Current Rate [1]	PROPOSED Calculated Annual Accrual [2]	Proposed Rate [2]	Adjustment Amount	Adjustment	
1	Steam 312 - SCR Catalyst	$ 1,663,431	4.08%	$ 244,622	0.60%	$ (1,418,809)	$ -	[3]
2	Total Production	$ 1,663,431		$ 244,622		$ (1,418,809)	$ -	

[1] NC-2602 - SCR Catalyst Current Depreciation rate - per Depreciation Study
[2] NC-2602 - SCR Catalyst Proposed Depreciation rate - per Depreciation Study
[3] In the supplemental January update, DEP is proposing to no longer flow cataylst depreciation expense through the fuel rider, therefore this adjustment is no longer needed.

Duke Energy Progress, LLC NC-2900
Docket No. E-2, Sub 1219 Supplemental
Update deferred balance and amortize storm costs February Update
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts depreciation and amortization, and income taxes for the amortization of the deferred storm expenses related to Hurricanes Florence, Michael and Winter Storm Diego (E-2 Sub 1193). The proforma also includes the estimated impact of Hurricane Dorian from September 2019.

Working capital and accumulated deferred taxes are adjusted to reflect the regulatory asset related to the deferred storm expenses.

October update
NC-2905 - Updated Storm costs per latest estimate

November update
NC-2905 - Updated Storm costs per latest estimate

December update
NC-2905 - Updated Storm costs per latest estimate

January update
NC-2902, NC-2903 and NC-2904 - updated composite depreciation rate to exclude AMR meters, not captured in previous versions; NC-2903 - Plant Balance includes Dorian Transmission capital as of September 30, 2019 - this was not reflected in NC-2903 in previous versions; NC-2905 - Updated Storm costs per latest estimate

February Supplemental
NC-2902 and NC-2903 - Updated monthly distribution assets/plant balance to reflect actual date in Power Plan and not date of storms; NC-2905 - Updated Storm costs per latest actuals; Transmission capital amounts were reduced to reflect insurance proceeds expected for Hurricane Florence; All capital amounts were updated to reflect actual data in Power Plan; NC-2906 - Added this adjustment to properly reflect amounts of storm deferral in General Plant

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2900
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization	NC-2901	43,201	43,717	(516)
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2901	(10,009)	(10,129)	120
15	Amortization of investment tax credit				-
16					
17	Total electric operating expenses	Sum L8 through L15	33,192	33,588	(397)
18					
19	Operating income	L4 - L17	$ (33,192)	$ (33,588)	$ 397
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	$ -	$ -	$ -
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment	NC-2901	604,817	612,045	(7,227)
35			-	-	-
36					
37	Less:				
38	Accumulated deferred taxes	NC-2901	(140,132)	(141,807)	1,675
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ 464,685	$ 470,238	$ (5,553)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2901
Supplemental
February Update

Line No.	Description	Distribution [1]	Transmission [2]	Production [3]	General Plant [4]	Total
		Cumulative Deferred Storm Costs Balance				
1	Impact to Income Statement Line Items					
2	Projected ending balance at August 31, 2020	$ 599,463	$ 45,084	$ 3,432	$ 39	$ 648,019
3	Years to amortize	15	15	15	15	
4	Impact to depreciation and amortization (L2 / L3)	$ 39,964	$ 3,006	$ 229	$ 3	$ 43,201
5						
6	Statutory tax rate					23.1693% [5]
7	Impact to income taxes (-L4 x L6)					$ (10,009)
8						
9	Impact to operating income (-L4 - L7)					$ (33,192)
10						
11	Impact to Rate Base Line Items					
12	Projected August 31, 2020 storm deferral balance for rate base (L2)	$ 599,463	$ 45,084	$ 3,432	$ 39	$ 648,019
13	Less: 1st year storm deferral amortization (-L4)	(39,964)	(3,006)	(229)	(3)	(43,201)
14	Projected storm deferral balance for rate base (L12 + L13)	$ 559,499	$ 42,078	$ 3,204	$ 37	$ 604,817
15						
16	Impact to working capital investment (L14)	$ 559,499	$ 42,078	$ 3,204	$ 37	$ 604,817
17						
18	Deferred tax rate	23.1693% [5]	23.1693% [5]	23.1693% [5]	23.1693% [5]	
19	Impact to accumulated deferred income tax (-L16 x L18)	$ (129,632)	$ (9,749)	$ (742)	$ (9)	$ (140,132)
20						
21	Impact to rate base (L16 + L19)	$ 429,867	$ 32,329	$ 2,461	$ 28	$ 464,685

[1] NC-2902 - Projected Storm Deferral Balance-Distribution
[2] NC-2903 - Projected Storm Deferral Balance-Transmission
[3] NC-2904 - Projected Storm Deferral Balance-Production
[4] NC-2906 - Projected Storm Deferral Balance-General Plant
[5] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2902
Supplemental
February Update

Projected Storm Deferral Balance-Distribution

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-		343,167	214	736	344,117	344,117
2	October 31, 2018	-	-	-	-	-	-	-	28,894	446	1,538	30,879	374,996
3	November 30, 2018	-	-	-	-	-	-	-		467	1,609	2,075	377,071
4	December 31, 2018	61,182	-	-	61,182	50	171	-	31,024	489	1,685	33,418	410,489
5	January 31, 2019	52,324	125	(125)	52,200	92	317	125		511	1,762	2,806	413,295
6	February 28, 2019	62,879	107	(231)	62,648	93	321	107		515	1,774	2,809	416,104
7	March 31, 2019	62,441	128	(359)	62,082	101	348	128		518	1,786	2,882	418,986
8	April 30, 2019	62,726	127	(486)	62,239	101	347	127		522	1,799	2,895	421,882
9	May 31, 2019	62,735	128	(614)	62,121	101	347	128		525	1,811	2,912	424,794
10	June 30, 2019	62,906	128	(742)	62,164	101	347	128		529	1,824	2,928	427,722
11	July 31, 2019	63,043	128	(870)	62,173	101	347	128		533	1,836	2,945	430,667
12	August 31, 2019	63,611	128	(998)	62,612	101	348	128		536	1,849	2,963	433,630
13	September 30, 2019	63,700	130	(1,128)	62,572	101	349	130	120,798	615	2,121	124,114	557,744
14	October 31, 2019	63,383	130	(1,257)	62,126	101	348	130		695	2,394	3,667	561,411
15	November 30, 2019	63,396	129	(1,386)	62,009	101	347	129		699	2,410	3,685	565,096
16	December 31, 2019	67,351	129	(1,516)	65,836	104	357	129		704	2,426	3,719	568,815
17	January 31, 2020	67,356	137	(1,653)	65,704	107	367	137		708	2,442	3,761	572,576
18	February 29, 2020	67,356	137	(1,790)	65,567	106	366	137		713	2,458	3,781	576,357
19	March 31, 2020	67,356	137	(1,927)	65,429	106	366	137		718	2,474	3,801	580,157
20	April 30, 2020	67,356	137	(2,064)	65,292	106	365	137		722	2,490	3,821	583,978
21	May 31, 2020	67,356	137	(2,201)	65,155	106	364	137		727	2,507	3,841	587,819
22	June 30, 2020	67,356	137	(2,338)	65,018	105	363	137		732	2,523	3,861	591,680
23	July 31, 2020	67,356	137	(2,476)	64,881	105	363	137		737	2,540	3,881	595,561
24	August 31, 2020	67,356	137	(2,613)	64,744	105	362	137		742	2,556	3,902	599,463
25	Total Costs Through August 31, 2020					2,092	7,211	2,613	523,883	14,317	49,347	599,463	

Line No.	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21%		
					Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

Line No.			
29	Book Depr Rate - Distribution	2.4434%	[2]
30	Book Depr Rate - Transmission	1.9019%	[2]
31	Book Depr Rate - Production	3.3708%	[2]

[1] NC-2905 - NC Storm Cost Data as of February 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2903
Supplemental
February Update

Projected Storm Deferral Balance-Transmission

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-		25,742	16	55	25,813	25,813
2	October 31, 2018	-	-	-	-	-	-	-	462	32	112	606	26,419
3	November 30, 2018	-	-	-	-	-	-	-		33	113	146	26,566
4	December 31, 2018	-	-	-	-	-	-	-	139	33	114	286	26,852
5	January 31, 2019	790	-	-	790	1	2	-		33	115	151	27,003
6	February 28, 2019	983	1	(1)	982	1	5	-		34	116	156	27,159
7	March 31, 2019	541	2	(3)	538	1	4	1		34	117	157	27,316
8	April 30, 2019	553	1	(4)	550	1	3	2		34	117	157	27,473
9	May 31, 2019	577	1	(5)	572	1	3	1		34	118	157	27,630
10	June 30, 2019	582	1	(5)	577	1	3	1		34	119	158	27,788
11	July 31, 2019	577	1	(6)	571	1	3	1		35	119	159	27,947
12	August 31, 2019	583	1	(7)	575	1	3	1		35	120	160	28,106
13	September 30, 2019	613	1	(8)	605	1	3	1	14,060	44	151	14,260	42,366
14	October 31, 2019	613	1	(9)	604	1	3	1		53	182	240	42,606
15	November 30, 2019	674	1	(10)	664	1	4	1		53	183	241	42,847
16	December 31, 2019	675	1	(11)	664	1	4	1		53	184	243	43,090
17	January 31, 2020	678	1	(12)	666	1	4	1		54	185	244	43,335
18	February 29, 2020	678	1	(13)	665	1	4	1		54	186	246	43,580
19	March 31, 2020	678	1	(14)	664	1	4	1		54	187	247	43,828
20	April 30, 2020	678	1	(16)	663	1	4	1		55	188	248	44,076
21	May 31, 2020	678	1	(17)	662	1	4	1		55	189	250	44,326
22	June 30, 2020	678	1	(18)	661	1	4	1		55	190	251	44,577
23	July 31, 2020	678	1	(19)	660	1	4	1		55	191	253	44,830
24	August 31, 2020	678	1	(20)	659	1	4	1		56	192	254	45,084
25	Total Costs Through August 31, 2020					21	71	19	40,403	1,028	3,543	45,084	

Line No.	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21% Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

Line No.	Description	Rate
29	Book Depr Rate - Distribution	2.4434% [2]
30	Book Depr Rate - Transmission	1.9019% [2]
31	Book Depr Rate - Production	3.3708% [2]

[1] NC-2905 - NC Storm Cost Data as of February 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2904
Supplemental
February Update

Projected Storm Deferral Balance-Production

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-		3,015	2	6	3,023	3,023
2	October 31, 2018	-	-	-	-	-	-	-	-	4	13	17	3,040
3	November 30, 2018	-	-	-	-	-	-	-		4	13	17	3,057
4	December 31, 2018	-	-	-	-	-	-	-	-	4	13	17	3,074
5	January 31, 2019	-	-	-	-	-	-	-		4	13	17	3,091
6	February 28, 2019	-	-	-	-	-	-	-		4	13	17	3,108
7	March 31, 2019	-	-	-	-	-	-	-		4	13	17	3,125
8	April 30, 2019	-	-	-	-	-	-	-		4	13	17	3,142
9	May 31, 2019	-	-	-	-	-	-	-		4	13	17	3,160
10	June 30, 2019	-	-	-	-	-	-	-		4	14	17	3,177
11	July 31, 2019	-	-	-	-	-	-	-		4	14	18	3,195
12	August 31, 2019	-	-	-	-	-	-	-		4	14	18	3,212
13	September 30, 2019	-	-	-	-	-	-	-		4	14	18	3,230
14	October 31, 2019	-	-	-	-	-	-	-		4	14	18	3,248
15	November 30, 2019	-	-	-	-	-	-	-		4	14	18	3,266
16	December 31, 2019	-	-	-	-	-	-	-		4	14	18	3,284
17	January 31, 2020	-	-	-	-	-	-	-		4	14	18	3,302
18	February 29, 2020	-	-	-	-	-	-	-		4	14	18	3,321
19	March 31, 2020	-	-	-	-	-	-	-		4	14	18	3,339
20	April 30, 2020	-	-	-	-	-	-	-		4	14	18	3,357
21	May 31, 2020	-	-	-	-	-	-	-		4	14	19	3,376
22	June 30, 2020	-	-	-	-	-	-	-		4	14	19	3,395
23	July 31, 2020	-	-	-	-	-	-	-		4	15	19	3,414
24	August 31, 2020	-	-	-	-	-	-	-		4	15	19	3,432
25	Total Costs Through August 31, 2020					-	-	-	3,015	94	324	3,432	

	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21%		
					Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

29	Book Depr Rate - Distribution	2.4434%	[2]
30	Book Depr Rate - Transmission	1.9019%	[2]
31	Book Depr Rate - Production	3.3708%	[2]

[1] NC-2905 - NC Storm Cost Data as of February 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2905
Supplemental
February Update

NC Storm Cost Data as of February 2020

Line No.	Description	Hurricane Florence - Sep 2018 System		Allocator	NC Retail	
1	Distr-O&M	413,650	[1]	Direct	368,245	[1]
2	Deductible				(25,078)	[6]
3	Distr-Capital	72,868	[1]	Direct	52,890	[1]
4						
5	Trans-O&M	43,140	[2]	59.7%	25,742	[2]
6	Trans-Capital	968	[2]	59.7%	577	[2]
7						
8	Prod-O&M	4,900	[3]	61.5%	3,015	[3]
9	Prod-Capital					
10						
11	General Plant -Capital	287	[4]	74.0%	213	[4]

Line No.	Description	Hurricane Michael - Oct 2018 System		Allocator	NC Retail	
1	Distr-O&M	30,102	[1]	Direct	28,894	[1]
2	Deductible					
3	Distr-Capital	8,944	[1]	Direct	8,944	[1]
4						
5	Trans-O&M	775	[2]	59.7%	462	[2]
6	Trans-Capital					
7						
8	Prod-O&M					
9	Prod-Capital					
10						
11	General Plant -Capital					

Line No.	Description	Winter Storm Diego - Dec 2018 System		Allocator	NC Retail	
1	Distr-O&M	31,600	[1]	Direct	31,024	[1]
2	Deductible					
3	Distr-Capital	1,483	[1]	Direct	1,483	[1]
4						
5	Trans-O&M	232	[2]	59.7%	139	[2]
6	Trans-Capital					
7						
8	Prod-O&M					
9	Prod-Capital					
10						
11	General Plant -Capital					

Line No.	Description	Hurricane Dorian - Sep 2019 [5] System		Allocator	NC Retail	
1	Distr-O&M	164,450	[1]	Direct	146,319	[1]
2	Deductible				(25,521)	[6]
3	Distr-Capital	4,222	[1]	Direct	4,041	[1]
4						
5	Trans-O&M	23,564	[2]	59.7%	14,060	[2]
6	Trans-Capital	169	[2]	59.7%	101	[2]
7						
8	Prod-O&M					
9	Prod-Capital					
10						
11	General Plant -Capital					

[1] Information provided by Distribution Finance and Asset Accounting. Storm Cost Data as of February 2020.
[2] Information provided by Transmission Finance and Asset Accounting. Storm Cost Data as of February 2020.
[3] Information provided by Generation Finance and Asset Accounting. Storm Cost Data as of February 2020.
[4] Information provided by Asset Accounting. Storm Cost Data as of February 2020.
[5] Estimate based upon best information available. To be updated in supplemental filings.
[6] Storm normalization adjustment

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2906
Supplemental (E)
February update

Projected Storm Deferral Balance-General Plant

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-			-	-	-	-
2	October 31, 2018	-	-	-	-	-	-	-	-	-	-	-	-
3	November 30, 2018	-	-	-	-	-	-	-		-	-	-	-
4	December 31, 2018	-	-	-	-	-	-	-	-	-	-	-	-
5	January 31, 2019	-	-	-	-	-	-	-		-	-	-	-
6	February 28, 2019	-	-	-	-	-	-	-		-	-	-	-
7	March 31, 2019	-	-	-	-	-	-	-		-	-	-	-
8	April 30, 2019	213	-	-	213	0	1	-		0	0	1	1
9	May 31, 2019	213	1	(1)	212	0	1	-		0	0	2	2
10	June 30, 2019	213	1	(2)	211	0	1	1		0	0	2	5
11	July 31, 2019	213	1	(3)	210	0	1	1		0	0	2	7
12	August 31, 2019	213	1	(4)	209	0	1	1		0	0	2	10
13	September 30, 2019	213	1	(4)	208	0	1	1		0	0	2	12
14	October 31, 2019	213	1	(5)	207	0	1	1		0	0	2	15
15	November 30, 2019	213	1	(6)	206	0	1	1		0	0	2	17
16	December 31, 2019	213	1	(7)	206	0	1	1		0	0	2	19
17	January 31, 2020	213	1	(8)	205	0	1	1		0	0	2	22
18	February 29, 2020	213	1	(9)	204	0	1	1		0	0	2	24
19	March 31, 2020	213	1	(10)	203	0	1	1		0	0	2	27
20	April 30, 2020	213	1	(11)	202	0	1	1		0	0	3	29
21	May 31, 2020	213	1	(12)	201	0	1	1		0	0	3	32
22	June 30, 2020	213	1	(12)	200	0	1	1		0	0	3	34
23	July 31, 2020	213	1	(13)	199	0	1	1		0	0	3	37
24	August 31, 2020	213	1	(14)	199	0	1	1		0	0	3	39
25	Total Costs Through August 31, 2020					6	19	13	-	0	1	39	

Line No.	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21%		
					Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Line No.	Depreciation Rates		
29	Book Depr Rate - Distribution	2.4434%	[2]
30	Book Depr Rate - Transmission	1.9019%	[2]
31	Book Depr Rate - Production	3.3708%	[2]
32	Book Depr Rate - General Plant - 394	5.0000%	[2]

[1] NC-2905 - NC Storm Cost Data as of February 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018

NC-3200
Supplemental
February Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts operation and maintenance expenses, income taxes, depreciation and amortization expense, electric plant in service and accumulated depreciation associated with the retirement of the Asheville Steam Electric Generating Plant in January 2020. It also adjusts for the regulatory asset established as a result of the early retirement, which was originally planned for December 2027.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October Update
NC-3205 Line 6 - corrected statutory tax rate; NC-3207 - Lines 2-5 corrected to update latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results.

November Update
Corrected typo on date of expected retirement

December Update
NC-3204 - Updated retirement date if December 2019 to January 2020; NC-3206 - Changes as a result of updates to NC-3207 noted below; NC-3207 - Lines 2-5 corrected to update latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results.

January Update
NC-3204 - Changed forecasted February 2020 plant in service balance back to original filing - to update actuals in February 2020; NC-3206 - Changes due to updates to NC-3207; NC-3207 - Lines 2-5 reflect latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results

February Update
NC-3201 - Updated Lines 18 and 21 to zero out plant in service and accumulated depreciation balances. Amounts are reflected in NC-1000; Line 26 reflects actual inventory retired; NC-3204 - Forecasted plant in service and accumulated depreciation balances eliminated. Amounts reflected in NC-1000; NC-3206 Changes due to updates to NC-3207; NC-3207 - Lines 2-5 reflect latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results.

Note: Plant in service and accumulated depreciation related to Asheville Steam Electric Generating plant was retired and reclassified to a regulatory asset in January 2020, with true-up adjustments in February 2020. The impacts of the retirement are included in actual plant in service data in NC-1000. NC-3200 has been updated to exclude impacts to plant in service and accumulated depreciation balances as a reuslt of the retirement.

Duke Energy Progress, LLC — NC-3200
Docket No. E-2, Sub 1219 — Supplemental
Reflect retirement of Asheville Steam Electric Generating Plant — February Update
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Source	Total NC Retail February	Application	Change
1			February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expens	NC-3201	(6,413)	(6,413)	-
11	Depreciation and amortization	NC-3201	(304)	(181)	(123)
12	General taxes	NC-3201	(1,032)	(1,032)	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-3201	1,795	1,767	29
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 thru L15	(5,954)	(5,859)	(95)
18					
19	Operating income	L4 - L17	$ 5,954	$ 5,859	$ 95
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-3201	$ -	$ (287,052)	$287,052
29	Accumulated depreciation and amortization	NC-3201	-	210,671	(210,671)
30	Electric plant in service, net	Sum L28 thru L29	-	(76,381)	76,381
31					
32	Add:				
33	Materials and supplies		(7,076)	(7,002)	(73)
34	Working capital investment		64,590	65,929	(1,339)
35					
36					
37	Less:				
38	Accumulated deferred taxes		(14,965)	(15,275)	310
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 thru L42	$ 42,550	$ (32,730)	$ 75,279
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3201
Supplemental
February Update

Line No.	Description	Total System		NC Retail Allocation	Total NC Retail	
1	Remove Direct O&M - Demand Related	$ (2,423)	[1]	61.5278% [2]	$ (1,491)	[1]
2	Remove Direct O&M - Energy Related	(8,055)	[1]	61.1093% [5]	(4,923)	[1]
3	Impact to O&M (L1 + L2)	$ (10,478)			$ (6,413)	
4						
5	Remove Depreciation related to Asheville Steam Electric Generating Plant	$ (17,069)	[3]	61.5278% [2]	$ (10,502)	
6	Amortize retired Asheville Steam Electric Generating Plant	16,575	[4]	61.5278% [2]	10,198	
7	Impact to Depreciation and Amortization (L5 + L6)	$ (494)			$ (304)	
8						
9	Remove Property Taxes	$ (1,678)	[3]	61.5278% [2]	$ (1,032)	
10	Impact to general taxes (L9)	$ (1,678)			$ (1,032)	
11						
12	Statutory tax rate	23.1693%	[6]		23.1693%	[6]
13	Impact to income taxes (-(L3 + L7 + L10) x L12)	$ 2,931			$ 1,795	
14						
15	Impact to operating income (-L3 - L7 - L10 - L13)	$ 9,719			$ 5,954	
16						
17	Rate Base investment:					
18	Remove Asheville Steam Electric Plant in Service	$ -	[3]	61.5278% [2]	$ -	
19	Remove Total Asheville Steam Electric Generating Plant Electric Plant in Service (L18)	$ -			$ -	
20						
21	Remove Asheville Steam Electric Generating Plant Accumulated Depreciation	$ -	[3]	61.5278% [2]	$ -	
22	Remove Total Asheville Steam Electric Generating Plant Accumulated Depreciation (L21)	$ -			$ -	
23						
24	Impact to net plant investment (L19 + L22)	$ -			$ -	
25						
26	Remove Asheville Steam Electric Generating Plant Inventory balance at retirement	$ (10,418)	[7]	67.9178% [8]	$ (7,076)	
27	Impact to materials and supplies (L26)	$ (10,418)			$ (7,076)	
28						
29	Regulatory Asset - Retired Asheville Steam Electric Generating Plant	$ 104,977	[4]	61.5278% [2]	$ 64,590	
30	Impact to working capital investment (L29)	$ 104,977			$ 64,590	
31						
32	Deferred tax rate	23.1693%	[6]		23.1693%	[6]
33	Impact to accumulated deferred income tax (-L30 x L32)	$ (24,323)			$ (14,965)	
34						
35	Impact to rate base (L30 + L27 + L24 + L33)	$ 70,237			$ 42,550	

[1] NC-3202 - Asheville Steam Electric Generating Plant Operating and Maintenance Expenses
[2] NC Retail Allocation Factor - DPALL
[3] NC-3203 - Asheville Steam Electric Generating Plant Asset Impacts in Proformas and the Test Year
[4] NC-3205 - Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization
[5] NC Retail Allocation Factor - E1ALL
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] Provided by Duke Energy Progress - Asset Accounting
[8] NC Retail Allocation Factor - PTDG

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018

NC-3202
Supplemental
February Update

Asheville Steam Electric Generating Plant Operating and Maintenance Expenses - For the 12 months ended December 31, 2018

Line No.	Account	2018 Asheville Coal	[3]	[2]
1	0500000 - Supervsn and Engrng - Steam Oper	345,452		DPALL
2	0500100 - Fossil Oper Superv&Engineer-Re	6,974		DPALL
3	0501150 - Coal & Other Fuel Handling	131,152		E1ALL
4	0501190 - Sale Of Fly Ash-Expenses	660,436		E1ALL
5	0502082 - Re-emission Chem Exp - Reagent	20,217		E1ALL
6	0502100 - Fossil Steam Exp-Other	994,055		DPALL
7	0505000 - Fossil Steam Exp-Other	(1,005)		DPALL
8	0506000 - Fossil Steam Exp-Other	1,077,141		DPALL
9	0507000 - Steam Power Gen-Op Rents	29		DPALL
10	0510000 - Suprvsn and Engrng-Steam Maint	129,357		E1ALL
11	0510100 - Suprvsn & Engrng-Steam Maint R	15,262		E1ALL
12	0511000 - Maint Of Structures-Steam	1,511,338		E1ALL
13	0512100 - Maint Of Boiler Plant-Other	3,320,486		E1ALL
14	0513100 - Maint Of Electric Plant-Other	744,459		E1ALL
15	0514000 - Maintenance - Misc Steam Plant	1,521,659		E1ALL
16	0514300 - Maintenance - Misc Steam Plant	250		E1ALL
17	0569200 - Maint Of Computer Software	12		DTALL
18	0570100 - Maint Stat Equip-Other- Trans	780		DTALL
19	0588100 - Misc Distribution Exp-Other	1		RB_PLT_O_DI_
20	Sum:	10,478,055	[1]	

[1] Direct Operation and Maintenance expenses provided by Regulated Utility Finance
[2] NC Retail Allocation factor to NC-3201
[3] Excludes O&M accounts recovered through fuel clause: 0501180, 0502030, 0502040, 0502070 and 0502080

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Steam Electric Generating Plant Asset Impacts in Proformas and the Test Year

Line No.	Description	Plant in Service 12/31/2018	Calculated Annual Accrual	Actual 12ME Depr Booked	Difference
1	Impact to Income Statement Line Items				
2	Steam Production Plant	$ 462,659 [1]	$ 15,551 [1]	$ 13,843 [1]	$ 1,708
3	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L2)	$ 462,659	$ 15,551	$ 13,843	$ 1,708
4	Impact of Asheville Steam Electric Generating Plant retirement to depreciation expense in NC-0802 (L3)				$ 1,708
5					
6			CURRENT	PROPOSED	
7		Plant	Calculated	Calculated	
8		in Service	Annual	Annual	Adjustment
9		12/31/2018	Accrual	Accrual	Amount
10	TOTAL STEAM PRODUCTION PLANT (311-316)	462,659 [1]	15,551 [1]	17,069 [1]	1,519
11	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L10)	$ 462,659	$ 15,551	$ 17,069	$ 1,519
12	Impact of retirement of Asheville Steam Electric Generating assets to depreciation expense in NC-2602 (L11)				$ 1,519
13					
14		Actual			
15		Net Change			
16		through		Proposed	Depr.
17		2/29/2020		Rate	Exp
18	Electric Plant in Service - Steam Production Balances	$ (462,659) [2]		3.69% [3]	$ -
19	Impact of Asheville Steam Electric Generating Plant retirement to depreciation expense in NC-1001	$ (462,659)			$ -
20					
21	Actual Depreciation Expense booked in 2018 for Asheville Steam Electric Generating Plant				$ 13,843 [1]
22					
23	Impact to depreciation and amortization (L4 + L12 + L19 + L21)				$ 17,069
24					
25		State - NC	State - SC		Total
26	12/31/2017 System Balances Subject to Property Tax	$ 29,182,104 [4]	$ 26,114,764 [4]		
27	2018 Property Tax Expense Paid	64,633 [4]	$ 36,850 [4]		
28	Average Property Tax Rate (L27 / L26)	0.22148%	0.14111%		
29					
30	Asheville Steam Electric Generating Plant in Service Balance at 12/31/2017	$ 461,159 [2]	$ 461,159 [2]		
31	2017 Percent of Asheville Steam Electric Generating Plant of System Balances Subject to Property Tax (L30 / L26)	1.5803%	1.7659%		
32	2018 Property Tax Expense Paid - Allocated to Asheville Steam Electric Generating Plant (L27 x L31)	$ 1,021	$ 651		$ 1,672
33					
34	12/31/2018 System Balances Subject to Property Tax	$ 30,893,953 [4]	$ 27,668,026 [4]		
35	Annualized Property Tax Expense (L28 x L34)	68,425	39,042		
36					
37	Asheville Steam Electric Generating Plant in Service Balance at 12/31/2018	$ 462,659 [2]	$ 462,659 [2]		
38	2018 Percent of Asheville Steam Electric Generating Plant of System Balances Subject to Property Tax(L37 / L34)	1.49757%	1.67218%		
39	Annualized Property Tax Expense - Allocated to Asheville Steam Electric Generating Plant (L35 x L38)	1,025	653		
40					
41	Property Tax Expense Adjustment - Allocated to Asheville Steam Electric Generating Plant (L39 - L32)	$ 3	$ 2		$ 5
42	Impact of Asheville Steam Electric Generating Plant assets to property tax in NC-0901 (L41)				$ 5
43					
44	Impact to general taxes (L32 + L41)				$ 1,678

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Steam Electric Generating Plant Asset Impacts in Proformas and the Test Year

Line No.	Description	Actual Net Change through 2/29/2020		Actual Balance at 12/31/2018		Adjustment Amount
45	Impact to Rate Base Line Items					
46	Electric Plant in Service - Steam Production Balances	$ (462,659) [2]				$ (462,659)
47	Impact of Asheville Steam Electric Generating Plant retirement to electric plant in service in NC-1002 (L46)	$ (462,659)				$ (462,659)
48						
49	Plant in Service balance for the Asheville Steam Electric Generating Plant			$ 462,659 [2]		$ 462,659
50						
51	Impact to electric plant in service (L47 + L49)					$ -
52						
53	Accumulated Depreciation - Steam Balances	$ 322,527 [2]				$ 322,527
54	Impact of Asheville Steam Electric Generating Plant retirement to accumulated depreciation in NC-1003 (L53)	$ 322,527				$ 322,527
55						
56	Accumulated Depreciation balance for the retired Asheville Steam Electric Generating Plant			$ (322,527) [2]		$ (322,527)
57						
58	Impact to accumulated depreciation (L54 + L56)					$ -
59						
60		Actual Plant		Calculated	Forecasted	
61		in Service	Current	Annual	12ME Depr	
62		2/29/2020	Rate	Accrual	Booked	Difference
63	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L41)	$ - [5]	2.99% [6]	$ -	- [2]	$ -
64	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L63)	$ -		$ -	$ -	$ -
65	Impact of Asheville Steam Electric Generating Plant retirement to accumulated depreciation in NC-1007 (L64)					$ -
66						
67	Impact to accumulated depreciation (L54 + L56 + L65)					$ -
68						
69	Total net plant (L51 + L67)					$ -

[1] Provided by Duke Energy Progress - Asset Accounting
[2] NC-3204 - Asheville Steam Electric Generating Plant - Balances
[3] Represents proposed new depreciation rates as of December 31, 2018 test period in the DEP depreciation study
[4] NC-0901 - Annualize property taxes on year end plant balances
[5] Actual Plant in Service amounts provided by Duke Energy Progress - Asset Accounting
[6] Calculated current rate based on the Calculated Annual Accrual amount divided by the Plant in Service at 12/31/2018 in Line 2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3204
Supplemental
February Update

Asheville Steam Electric Generating Plant - Balances

Line No.	Description	ACTUALS Dec 2017 [1]	Dec 2018 [1]	Feb 2020 [2]	Net Change
1		a	b	c	d = c - b
2	Electric Plant in Service - Balances				
3	Steam Production:				
4	Asheville Steam Electric Generating Plant	$ 461,159	$ 462,659	$ -	$ (462,659)
5	Steam Production Total (Sum L4)	$ 461,159	$ 462,659	$ -	$ (462,659)
6					
7	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L5)	$ 461,159	$ 462,659	$ -	$ (462,659)
8					
9	Accumulated Depreciation - Balances				
10	Steam Production:				
11	Asheville Steam Electric Generating Plant - Life reserve		$ (314,952)	$ -	$ 314,952
12	Asheville Steam Electric Generating Plant - COR reserve		(7,575)	-	7,575
13	Steam Production Total (Sum L11)		$ (322,527)	$ -	$ 322,527
14					
15	Balance in Accumulated Depreciation related to Asheville Steam Electric Generating Plant retirement (L13)		$ (322,527)	$ -	$ 322,527
16					
17	Depreciation Expense - Forecasted 12 Months Activity as of February 29, 2020				
18	Steam Production:				
19	Asheville Steam Electric Generating Plant (-L11 col. d x 12/14)				$ -
20	Steam Production Total				$ -
21					
22	Depreciation Expense related to Asheville Steam Electric Generating Plant retirement				$ -

[1] Provided by Duke Energy Progress - Asset Accounting
[2] Plant in service and accumulated depreciation related to Asheville Steam Electric Generating plant was retired and reclassified to a regulatory asset in January 2020, with true-up adjustments in February 2020. The impacts of the retirement of Asheville plant are included in actual plant in service data in NC-1000. NC-3200 has been updated to exclude impacts to plant in service and accumulated depreciation balances as a reuslt of the retirement.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3205
Supplemental
February Update

Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization

Line No.	Description	Total Carolinas	NC Retail Allocation	Total NC Retail
1	Impact to Income Statement Line Items			
2	Projected August 31, 2020 retired Asheville plant regulatory asset balance	$ 121,553 [1]	61.5278% [2]	$ 74,789
3	Years to amortize	7		7
4	Impact to depreciation and amortization (L2 / L3)	$ 16,575		$ 10,198
5				
6	Statutory tax rate	23.1693% [3]		23.1693% [3]
7	Impact to income taxes (-L4 x L6)	$ (3,840)		$ (2,363)
8				
9	Impact to operating income (-L4 - L7)	$ (12,735)		$ (7,836)
10				
11	Impact to Rate Base Line Items			
12	Projected August 31, 2020 retired Asheville plant regulatory asset balance (L2)	$ 121,553		$ 74,789
13	Less: 1st year amortization (-L4)	(16,575)		(10,198)
14	Projected deferral balance for rate base (L12 + L13)	$ 104,977		$64,590
15				
16	Impact to working capital investment (L14)	$ 104,977		$64,590
17				
18	Deferred tax rate	23.1693% [3]		23.1693% [3]
19	Impact to accumulated deferred income tax (-L16 x L18)	$ (24,323)		$ (14,965)
20				
21	Impact to rate base (L16 + L19)	80,655		49,625

[1] NC-3206 - Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization Schedule at 8/31/2020, Line 7
[2] NC Retail Allocation Factor - DPALL
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3206
Supplemental
February Update

Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization Schedule

Line No.		Beginning Balance	Monthly Amortization Expense	Ending Balance
1	2/1/2020	$ 132,701 [1]	$ (1,593) [2]	$ 131,109
2	3/1/2020	131,109	(1,593)	129,516
3	4/1/2020	129,516	(1,593)	127,923
4	5/1/2020	127,923	(1,593)	126,331
5	6/1/2020	126,331	(1,593)	124,738
6	7/1/2020	124,738	(1,593)	123,146
7	8/1/2020	123,146	(1,593)	121,553

[1] NC-3207, Line 6
[2] NC-3207, Line 15

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018

NC-3207
Supplemental
February Update

Retired Asheville Steam Electric Generating Plant Regulatory Asset Schedule and Amortization Calculation

Line No.	Description	Total	
1	Calculation of Net Book Value of retired Asheville Steam Electric Generating Plant		
2	Electric Plant in Service balance	$ 457,660,037	[1]
3	Accumulated Depreciation balance	(328,501,436)	[1]
4	Materials and Supplies Inventory	11,008,080	[1]
5	COR Reserve balance	(7,465,272)	[1]
6	Net Book Value of Asheville Steam Electric Generating Plant at retirement, 01/31/2019 (L2 + L3 + L4 + L5)	$ 132,701,409	[4]
7			
8	Calculation of monthly amortization of Asheville Steam Electric Generating Plant at retirement, 01/31/2020		
9	Life Net Book Value to be recovered (L2 + L3 + L4)	$ 140,166,680	
10	Remaining COR to be recovered after retirement of plant	11,134,728	[2]
11	Total to be recovered for Asheville Steam Electric Generating Plant at end of amortization period (L9 + L10)	$ 151,301,409	
12			
13	Monthly Amortization expense, Life Net Book Value (L9 /95 months)	$ (1,475,439)	[3]
14	Monthly Amortization expense, COR (L10 /95 months)	(117,208)	[3]
15	Total monthly amortization expense	$ (1,592,646)	

[1] Provided by Duke Energy Progress Asset Accounting - estimated net book value of Asheville Steam Electric Generating plant after retirement date in January 2020. Includes true-up adjustments as of 02/29/2020 (excludes Land and General plant)

[2] Represents the most recent dismantlement study estimate of $18.6 million, less the COR Reserve balance at the date of retirement, Line 5.

[3] Monthly amortization begin date February 1, 2020 through original retirement date December 31, 2027 = 95 months

[4] Duke Energy Progress Asset Accounting expects additional entries to impact retirement finalization in February 2020. An update will be provided in the February 2020 supplemental filing.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for CertainTeed payment obligation
For the test period ended December 31, 2018

NC-3300
Supplemental
October Update

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expense to account for the CertainTeed payment obligation.

The impact to operations and maintenance expense was determined by a payment schedule defined in a confidential settlement agreement with CertainTEED Gypsum NC, Inc. (CTG) effective October 1, 2018. Under the agreement annual payments are to be made by DEP starting in 2018 through 2029 for a total of $88.9M on a system basis. The amount is allocated to NC Retail based on the energy allocation factor, and recovered over an 11-year period to align with the payment period.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update

Updated Summary to remove CertainTeed cost adjustment in accordance with Commission order under Docket No. E-2, Sub 1204

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for CertainTeed payment obligation
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3300
Supplemental
October Update

Line No.	Description	Source	Total NC Retail		
1			Supplemental (A)	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-3301	-	4,939	(4,939)
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-3301	-	(1,144)	1,144
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	-	3,794	(3,794)
18					
19	Operating income	L4 - L17	$ -	$ (3,794)	$ 3,794
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization				
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for CertainTeed payment obligation
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3301
Supplemental
October Update

Line No.	Description	Total System		NC Retail Allocation		NC Retail	
1							
2	Actual Payments Made in 2018	$ 2,100	[1]				
3	Remaining Contracted Payment Obligation (2019 - 2029)	86,800	[1]				
4	Total Contractual Payments (L2 + L3)	$ 88,900		61.1093%	[2]	$ 54,326	
5	Number of Years over which to recover (2019 - 2029)					11	[1]
6	Impact to O&M (L4 / L5)					$ 4,939	
7							
8	Statutory tax rate					23.1693%	[3]
9	Impact to income taxes (-L6 x L8)					$ (1,144)	
10							
11	Impact to operating income (-L6 - L9)					$ (3,794)	

[1] From Settlement Agreement with CertainTeed Gypsum NC, Inc (CTG)
[2] NC Retail Allocation Factor - E1All
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

NC-3400
Supplemental
February Update

Detailed Narrative Explanation of Adjustment

This pro forma adjusts depreciation expense and income taxes for the amortization of deferred costs related to Asheville Combined Cycle. The Company is seeking a deferral of depreciation, property taxes, incremental O&M and return associated with the Asheville Combined Cycle from the date the plant is estimated to go into operation, December 2019, until rates are effective in September 2020.

The impact to operating income was determined as follows:

The impact to depreciation expense reflects an annual level of amortization of deferred costs related to Asheville Combined Cycle, including a return on investment. Deferred costs are being amortized over a three year period.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

The impact to rate base was determined as follows:

The impact to working capital is determined by including the regulatory asset balance in rate base and offsetting it with one year of amortization. In addition, the asset is offset by associated ADIT.

December Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through December 2019.
Updated NC-3405 for the estimated amount to go in service through February 2020.

January Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through January 2019.
Updated NC-3405 for the estimated amount to go in service through February 2020.

February Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through February 2020; updated NC-3402 and NC-3403 to exclude O&M from Asheville CC deferral; NC-3406 updated to include the actual level of inventory on hand at Asheville CC when it became operational (01/31/2020)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3400
Supplemental
February Update

Line No.	Description	Source	Total NC Retail		
1			February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-3401	6,109	6,109	-
11	Depreciation and amortization	NC-3401	11,576	13,594	(2,018)
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-3401	(4,098)	(4,565)	468
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	13,588	15,138	(1,550)
18					
19	Operating income	L4 - L17	$ (13,588)	$ (15,138)	$ 1,550
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies	NC-3401	3,488	3,735	(248)
34	Working capital investment	NC-3401	23,151	27,188	(4,036)
35					
36					
37	Less:				
38	Accumulated deferred taxes	NC-3401	(5,364)	(6,299)	935
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ 21,275	$ 24,624	$ (3,349)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3401
Supplemental
February Update

Line No.	Description	Total NC Retail	
1	Impact to Income Statement Line Items		
2	Average Annual Combined Cycle O&M	$ 6,109	[1]
3	Impact to O&M (L2)	$ 6,109	
4			
5	Balance for amortization	$ 34,727	[2]
6	Years to amortize	3	
7	Impact to depreciation and amortization (L5 / L6)	$ 11,576	
8			
9	Statutory tax rate	23.1693%	[3]
10	Impact to income taxes (-(L3+ L7) x L9)	$ (4,098)	
11			
12	Impact to operating income (-L3 - L7 -L10)	$ (13,588)	
13			
14			
15	Impact to Rate Base Line Items		
16	Estimated level of inventory at Asheville CC at operational date	$ 3,488	[1]
17	Impact to materials and supplies (L16)	$ 3,488	
18			
19	Regulatory asset at Sep 1, 2020 (L5)	$ 34,727	
20	Less first year of amortization (-L7)	(11,576)	
21	Impact to working capital investment (Sum L19 through L20)	$ 23,151	
22			
23	Deferred tax rate	23.1693%	[3]
24	Impact to accumulated deferred income tax (-L21 x L23)	$ (5,364)	
25			
26	Impact to rate base (L17 + L21 + L24)	$ 21,275	

[1] NC-3406 Asheville Combined Cycle - Average O&M and Inventory Balances
[2] NC-3402 Expected Balance of Deferred Costs at September 1, 2020 - Asheville Combined Cycle (NC Retail)
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3402
Supplemental
February Update

Expected Balance of Deferred Costs at September 1, 2020 - Asheville Combined Cycle - NC Retail

Line No.	Description	Other Production [1]	Transmission [2]	Total NC Retail	
1	Deferred Cost of Capital	$ 16,959	$ 475	$ 17,433	[1]
2	Deferred Depreciation	11,219	94	11,313	[1]
3	Deferred O&M Expense	4,139	-	4,139	[1]
4	Deferred Property Tax Expense	1,049	20	1,069	[1]
5	After-Tax Return on Deferred Expenses	758	16	773	[1]
6	Total expected deferral balance in Regulatory Asset (Sum L1 through L5)	$ 34,123	$ 605	$ 34,727	

[1] NC-3403 - Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail, Line 13

[2] NC-3404 - Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail, Line 13

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail

Line No.	Description	Plant Bal [1]	ADIT Bal [2]	Average Inventory Bal [3]	Accumulated Depreciation	Remove CWIP in Rate Base [4]	Rate Base		Deferred Cost of Capital 2019	Deferred Cost of Capital 2020	Deferred Cost of Capital Total		Deferred Depreciation 2019	Deferred Depreciation 2020	Deferred Depreciation Total	Deferred O&M Expense [5] 2019	Deferred O&M Expense [5] 2020	Deferred O&M Expense [5] Total
1																		
2	Plant in Service Dec 2019 costs (U1 12/27/19)	302,260	(28,013)	3,488	-	(102,930)	174,805		162		162		-		-	66		66
3	Jan 2020 costs	347,271	(32,184)	3,488	(1,035)	(102,930)	214,610			1,546	1,546			1,035	1,035		509	509
4	Feb 2020 costs	347,271	(32,184)	3,488	(2,223)	(102,930)	213,421			1,537	1,537			1,189	1,189		509	509
5	Mar 2020 costs	456,208	(32,184)	3,488	(3,412)	(102,930)	321,170			2,314	2,314			1,189	1,189		509	509
6	Apr 2020 costs	456,208	(32,184)	3,488	(4,973)	(102,930)	319,608			2,302	2,302			1,561	1,561		509	509
7	May 2020 costs	456,208	(32,184)	3,488	(6,534)	(102,930)	318,047			2,291	2,291			1,561	1,561		509	509
8	Jun 2020 costs	456,208	(32,184)	3,488	(8,096)	(102,930)	316,486			2,280	2,280			1,561	1,561		509	509
9	Jul 2020 costs	456,208	(32,184)	3,488	(9,657)	(102,930)	314,924			2,269	2,269			1,561	1,561		509	509
10	Aug 2020 costs	456,208	(32,184)	3,488	(11,219)	(102,930)	313,363			2,257	2,257			1,561	1,561		509	509
11																		
12	Total Costs Through Aug 31,2020								162	16,796	16,959		-	11,219	11,219	66	4,073	4,139
13																		
14								After-Tax	Tax		Pre-Tax							
15	Cost of Capital [8]:							Equity	Rate		Equity							
16	Assumed Capital Structure:																	
17	Long-Term Debt							48.00%										
18	Common Equity							52.00%										
19																		
20	Cost Rates:																	
21	Long-Term Debt							4.05%			4.0500%							
22	Common Equity							9.90%	23.1693%		12.8855%							
23								13.95%			16.9355%							
24	Cost Components:																	
25	Long-Term Debt							1.9440%			1.9440%	22.4884%						
26	Common Equity							5.1480%	23.1693%		6.7004%	77.5116%						
27	Rate							7.0920%			8.6444%	100.0000%						
28																		
29	Depreciation Rates:																	
30	Book depreciation rate - Other Production - Asheville CC							4.11%	[10]									
31	Average Property Tax Rate							0.3626%	[9]									
32	Deferred tax rate								23.1693% [7]									

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail

Line No.	Description	Deferred Property Tax Expense [6] 2019	2020	Total	After-Tax Return on Deferred Expenses 2019	2020	Total	Deferred Total 2019	2020	Total
1										
2	Plant in Service Dec 2019 costs (U1 12/27/1	12		12	0		0	240		240
3	Jan 2020 costs		105	105		11	11		3,205	3,205
4	Feb 2020 costs		105	105		30	30		3,370	3,370
5	Mar 2020 costs		138	138		53	53		4,202	4,202
6	Apr 2020 costs		138	138		78	78		4,589	4,589
7	May 2020 costs		138	138		106	106		4,605	4,605
8	Jun 2020 costs		138	138		133	133		4,621	4,621
9	Jul 2020 costs		138	138		160	160		4,637	4,637
10	Aug 2020 costs		138	138		187	187		4,653	4,653
11										
12	Total Costs Through Aug 31,2020	12	1,037	1,049	0	758	758	240	33,883	34,123
13										
14										
15	Cost of Capital [8]:									
16	Assumed Capital Structure:									
17	Long-Term Debt									
18	Common Equity									
19										
20	Cost Rates:									
21	Long-Term Debt									
22	Common Equity									
23										
24	Cost Components:									
25	Long-Term Debt									
26	Common Equity									
27	Rate									
28										
29	Depreciation Rates:									
30	Book depreciation rate - Other Production - Asheville CC									
31	Average Property Tax Rate									
32	Deferred tax rate									

[1] NC-3405 - Asheville Combined Cycle - Plant in Service - Costs by Month
[2] Other Production additions that qualify for bonus depreciation multiplied by 40% and then the deferred tax rate on Line 32
[3] NC-3406 - Asheville Combined Cycle - Average O&M and Inventory Balances, Line 13
[4] NC-1011 - Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142
[5] O&M during the deferral period was removed from the calculation for February supplemental filing.
[6] Plant Balance column divided by 12 months multiplied by Line 31.
[7] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[8] Cost of capital rates from Docket No. E-2, Sub 1142
[9] NC-0901 - Annualize property taxes on year end plant balances - Average property tax rate-Combined NC and SC
[10] Asheville CC composite depreciation rate provided by Asset Accounting
[11] Adjusted to reflect a rates effective date of Sep 1, 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail

Line No.	Description	Plant Bal [1]	ADIT Bal [2]	Average Inventory Bal [3]	Accumulated Depreciation	Remove CWIP in Rate Base	Rate Base		Deferred Cost of Capital 2019	Deferred Cost of Capital 2020	Deferred Cost of Capital Total	Deferred Depreciation 2019	Deferred Depreciation 2020	Deferred Depreciation Total	Deferred O&M Expense [4] 2019	Deferred O&M Expense [4] 2020	Deferred O&M Expense [4] Total
1																	
2	Plant in Service Dec 2019 costs	7,422	(67)	-	-	-	7,354		53		53			-	-		-
3	Jan 2020 costs	7,431	(67)	-	(12)	-	7,351			53	53		12	12		-	-
4	Feb 2020 costs	7,436	(67)	-	(24)	-	7,345			53	53		12	12		-	-
5	Mar 2020 costs	7,436	(67)	-	(35)	-	7,333			53	53		12	12		-	-
6	Apr 2020 costs	7,436	(67)	-	(47)	-	7,322			53	53		12	12		-	-
7	May 2020 costs	7,436	(67)	-	(59)	-	7,310			53	53		12	12		-	-
8	Jun 2020 costs	7,436	(67)	-	(71)	-	7,298			53	53		12	12		-	-
9	Jul 2020 costs	7,436	(67)	-	(82)	-	7,286			52	52		12	12		-	-
10	Aug 2020 costs	7,436	(67)	-	(94)	-	7,275			52	52		12	12		-	-
11																	
12	Total Costs Through Aug 31,2020								53	422	475	-	94	94	-	-	-
13																	
14								After-Tax	Tax		Pre-Tax						
15	Cost of Capital [7]:							Equity	Rate		Equity						
16	Assumed Capital Structure:																
17	Long-Term Debt							48.00%									
18	Common Equity							52.00%									
19																	
20	Cost Rates:																
21	Long-Term Debt							4.05%			4.0500%						
22	Common Equity							9.90%	23.1693%		12.8855%						
23								13.95%			16.9355%						
24	Cost Components:																
25	Long-Term Debt							1.9440%			1.9440%	22.4884%					
26	Common Equity							5.1480%	23.1693%		6.7004%	77.5116%					
27	Rate							7.0920%			8.6444%	100.0000%					
28																	
29	Depreciation Rates:																
30	Book depreciation rate - Transmission							1.90%	[9]								
31	Average Property Tax Rate							0.3626%	[8]								
32	Deferred tax rate								23.1693% [6]								

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail

Line No.	Description	Deferred Property Tax Expense [5] 2019	2020	Total	After-Tax Return on Deferred Expenses 2019	2020	Total	Deferred Total 2019	2020	Total
1										
2	Plant in Service Dec 2019 costs	2		2	0		0	55		55
3	Jan 2020 costs		2	2		1	1		67	67
4	Feb 2020 costs		2	2		1	1		68	68
5	Mar 2020 costs		2	2		1	1		68	68
6	Apr 2020 costs		2	2		2	2		68	68
7	May 2020 costs		2	2		2	2		69	69
8	Jun 2020 costs		2	2		3	3		69	69
9	Jul 2020 costs		2	2		3	3		69	69
10	Aug 2020 costs		2	2		3	3		70	70
11										
12	Total Costs Through Aug 31,2020	2	18	20	0	15	16	55	549	605
13										
14										
15	Cost of Capital [7]:									
16	Assumed Capital Structure:									
17	Long-Term Debt									
18	Common Equity									
19										
20	Cost Rates:									
21	Long-Term Debt									
22	Common Equity									
23										
24	Cost Components:									
25	Long-Term Debt									
26	Common Equity									
27	Rate									
28										
29	Depreciation Rates:									
30	Book depreciation rate - Transmission									
31	Average Property Tax Rate									
32	Deferred tax rate									

[1] NC-3405 - Asheville Combined Cycle - Plant in Service - Costs by Month
[2] Transmission additions that qualify for bonus depreciation multiplied by 40% and then the deferred tax rate on Line 32
[3] Not estimating incremental inventory for the transmission additions.
[4] Not estimating incremental O&M for the transmission additions.
[5] Plant Balance column divided by 12 months multiplied by Line 31.
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] Cost of capital rates from Docket No. E-2, Sub 1142
[8] NC-0901 - Annualize property taxes on year end plant balances - Average property tax rate-Combined NC and SC
[9] NC-0802 - Adjustment of Depreciation Expense to Reflect Plant in Service for 12 Months Ended December 31, 2018, Transmission Other depr rate
[10] Adjusted to reflect a rates effective date of Sep 1, 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3405
Supplemental
February Update

Asheville Combined Cycle - Plant in Service - Costs by Month

Line No.	Year	Month	System Other Production		System Transmission		NC Retail Allocation		NC Retail Allocation		NC Retail Other Production	NC Retail Transmission
1												
2	2019	12	491,258	[1]	12,438	[1]	61.5278%	[2]	59.6699%	[3]	302,260	7,422
3	2020	1	564,413	[1]	12,453	[1]	61.5278%	[2]	59.6699%	[3]	347,271	7,431
4	2020	2	564,413	[1]	12,462	[1]	61.5278%	[2]	59.6699%	[3]	347,271	7,436
5	2020	3	741,467	[4][5]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	456,208	7,436
6	2020	4	741,467	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	456,208	7,436
7	2020	5	741,467	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	456,208	7,436
8	2020	6	741,467	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	456,208	7,436
9	2020	7	741,467	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	456,208	7,436
10	2020	8	741,467	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	456,208	7,436
11	Total Project Cost		$ 741,467		$ 12,462						$ 456,208	$ 7,436

[1] Estimated amounts provided by Asheville Combined Cycle Project Management
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - DTALL
[4] Forecasted amount updated as of February 29, 2020 is based on actual amounts in service and the expected plant impacts of $177,054 in March 2020 when Unit 8 is expected to be in operation.
[5] Adjusted the Asheville CC project costs to exclude Task Force consulting expenses noted in PS DR 125-5 from rate base.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

NC-3406
Supplemental
February Update

Asheville Combined Cycle - Average O&M and Inventory Balances

Line No.	Account	2017 HF Lee CC	2018 HF Lee CC	2017 Sutton CC	2018 Sutton CC	Average Annual CC O&M [1]	NC Retail Allocation		Total NC Retail
1	0546000 - Suprvsn and Enginring - Ct Oper	$ 184,395	$ 201,075	$ 465,609	$ 358,980	$ 302,515	61.5278%	[2]	$ 186,131
2	0548100 - Generation Expenses - Other Ct	239,757	233,516	297,994	306,949	269,554	61.5278%	[2]	165,851
3	0548200 - Prime Movers - Generators - Ct	-	-	1,004	23,889	6,223	61.5278%	[2]	3,829
4	0549000 - Misc - Power Generation Expenses	2,763,570	3,487,354	2,631,701	2,030,183	2,728,202	61.5278%	[2]	1,678,603
5	0551000 - Suprvsn and Enginring - Ct Maint	354,997	367,123	461,594	331,587	378,825	61.1093%	[3]	231,497
6	0552000 - Maintenance of Structures - Ct	3,095,563	1,812,816	1,870,970	2,092,865	2,218,054	61.1093%	[3]	1,355,437
7	0553000 - Maint - Gentg and Elect Equip - Ct	2,776,375	2,902,538	2,150,399	1,776,630	2,401,486	61.1093%	[3]	1,467,531
8	0554000 - Misc Power Generation Plant - Ct	1,427,348	1,835,888	1,722,978	1,691,109	1,669,331	61.1093%	[3]	1,020,117
9	0570100 - Maint Stat Equip - Other_Trans	-	2,272	-	-	568	59.6699%	[4]	339
10	Total O&M	$ 10,842,006	$ 10,842,583	$ 9,602,248	$ 8,612,192	$ 9,974,757			$ 6,109,335
11									
12									
13	Actual level of inventory for Asheville CC at the time the plant becomes operational (01/31/2020)					$5,135,089 [5]	67.9178%	[6]	$ 3,487,639

[1] Direct Operation and Maintenance expenses, excluding outage costs, provided by Regulated Utility Finance
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - E1ALL
[4] NC Retail Allocation Factor - DTALL
[5] Estimated Inventory level provided by Supply Chain
[6] NC Retail Allocation Factor - PTDG

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Correct Lead Lag Per Books amount
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3600
Supplemental
February Update

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

The Company has updated the lead lag study for the way payroll deductions and tax related to incentive pay were calculated as well as incorporated corrections to formulas.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Correct Lead Lag Per Books amount
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3600
Supplemental
February Update

Line No.	Description	Source	Total NC Retail February	Total NC Retail Application	Total NC Retail Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance		-	-	-
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes		-	-	-
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	-	-	-
18					
19	Operating income	L4 - L17	$ -	$ -	$ -
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		(8,580)	-	(8,580)
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (8,580)	$ -	$ (8,580)
45					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Correct Lead Lag Per Books amount
For the test period ended December 31, 2018

NC-3601
Supplemental
February Update

Line No	Description	Actual Annual Expense [A]	Lead (Lag) Days [B]	Weighted Amount [C]	Per Books COS	Adjustment
	Calculation of NC Retail Amount:					
1	Total Revenue Lag	$ (3,657,503)	42.13	$ (154,105,865)		
2						
3	Operation & Maintenance Expense	$ 2,091,224	33.30	$ 69,630,312		
4	Depreciation and Amortization	669,787	0.00	-		
5	Taxes Other Than Income Taxes	102,197	132.70	13,561,920		
6	Interest on Customer Deposits	7,971	137.50	1,096,011		
7	Net Income Taxes	112,986	-20.60	(2,327,337)		
8	ITC	(2,134)	0.00	-		
9	Income for Return	675,472	27.48	18,562,554		
10	Total Requirements (Sum L3:L9)	$ 3,657,503	27.48	$ 100,523,460		
11						
12	Revenue Lag Days (L1)		42.13			
13	Requirements Lead Days (-L10)		-27.48			
14	Net Lag Days (L12 + L13)		14.65			
15	Daily Requirements (Line 9, Col. A divided by 365)			$ 10,021		
16						
17	Estimated Cash Working Capital Requirements (L14 x L15)			$ 146,801		
18	Add: Cash Working Capital Related to NC Sales Tax			4,760		
19	Total Cash Working Capital Requirements (L17 + L18)			$ 151,561		
20						
21	**Calculation of Total Company and Jurisdictional Amounts:**					
22	NC Retail Factor			67.0949% [1]		
23					**Per Books COS**	**Adjustment**
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 225,890	$ 238,679	$ (12,789)
25						
26	NC Retail Factor			67.0949%	67.0949%	
27	SC Retail Factor			10.0953%	10.0953%	
28	NC Wholesale Factor			14.3676%	14.3676%	
29	SC Wholesale Factor			0.2761%	0.2761%	
30	NCEMPA Factor			8.1661%	8.1661%	
31	Total (Sum L26 through L30)			100.0000%	100.0000%	
32						
33	NC Retail Cash Working Capital Requirement (L24 x L26)			$ 151,561	$ 160,141	$ (8,580)
34	SC Retail Cash Working Capital Requirement (L24 x L27)			22,804	24,095	(1,291)
35	NC Wholesale Cash Working Capital Requirement (L24 x L28)			32,455	34,292	(1,837)
36	SC Wholesale Cash Working Capital Requirement (L24 x L29)			624	659	(35)
37	NCEMPA Cash Working Capital Requirement (L24 x L30)			18,446	19,491	(1,044)
38	Total Company Cash Working Capital Requirement (Sum L33:L36)			$ 225,890	$ 238,679	$ (12,789)
						-

[1] NC Retail Allocation Factor - Net Book Plant

I/A

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

SMITH
Supplemental Exhibit 2
Page 1

Line No.	Description	NC RETAIL	Reference
1	Additional base revenue requirement	$ 534,344	Smith Supplemental Exhibit 1
2	REVISED Annual EDIT Rider 1	7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback	(126,128)	Smith Supplemental Exhibit 4
4	Regulatory Asset and Liability Rider	(2,091)	Smith Exhibit 5
5	Subtotal	(120,837)	Sum L3 - L17
6	Net Revenue Increase	$ 413,507	

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Supplemental Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

			Federal EDIT - Protected NC Retail	Federal EDIT - Unprotected, PP&E related NC Retail	Federal EDIT - Unprotected, non PP&E related NC Retail	NC EDIT NC Retail	Deferred Revenue NC Retail	Total NC Retail
			(A)	(B)	(C)	(D)	(E)	(F)
1	Regulatory Federal EDIT liabilIty including gross up on the books as of 12/31/2018, based on 2017 tax returns	[1]	$ (854,917)	$ (326,704)	$ 4,862	$ (23,726)		(1,200,485)
2	Adjustment to implement ASU 2018-02	[1]			$ (34)	$ -		(34)
2a	Adjustment for Amended 2017 Federal Return	[1]		$ (415)				(415)
3	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2018-12/31/2018	[1]	$ 30,548		$ (30,548)	$ -		-
4	Regulatory Federal EDIT liability including gross up as of 12/31/2018, adjusted for the implementation of ASU 2018-0	[1]	$ (824,369)	$ (327,119)	$ (25,719)	$ (23,726)	$ -	(1,200,934)
5	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2019-8/31/2020	[1]	$ 50,913		$ (50,913)	$ -		-
6	Deferred revenues related to 2017 Federal Tax Rate Change as of 12/31/2018	[1]					$(108,392)	(108,392)
7	Other projected updates through 2/29/2020	[2]				$ (271)	$ (1,923)	(2,194)
8	Regulatory liabilIty for federal tax change including gross up for NC Retail, for Year 1 rider calculation (Sum of L4 to L7)		$ (773,457)	$ (327,119)	$ (76,631)	$ (23,998)	$(110,315)	(1,311,519)
9	Annual Amortization percentage		3.57%	5.00%	20.00%	20.00%	50.00%	9.32%
10	Liability for Annual amortization amount (Col A: L1 , Col B to E: L8)		$ (854,917)	$ (327,119)	$ (76,631)	$ (23,998)	$ (110,315)	(1,392,980)
11	Annual amortization amount (L9 x L10)	[3]	(30,548)	(16,356)	(15,326)	(4,800)	(55,157)	(122,187)
12	Years of rider amortization		27.99	20	5	5	2	11

[1] Excess deferred tax liability (EDIT) as of 12/31/2018 by jurisdiction, and forecast transition to new rates effective date between categories based on Tax analysis of ADIT.
Federal EDIT related to the federal tax changes booked to the 0254036 and 0254038 accounts is included in other Working Capital in the per books cost of service.
NC EDIT related to the NC state tax reduction deferred to the 0254150 account not included for recovery in NC EDIT rider approved in prior DEP NC rate case.
This NC EDIT is included in other Working Capital in the per books cost of service.
Revenues deferred for federal tax changes with accrued returns in the 0229010 account, are currently excluded from rate base in the per books COSS.

[2] Projected updates to the Federal and NC tax EDIT during 2019 by Tax
Supplemental Smith Exhibit 4, Page 3, Line 1 return accruals on deferred revenues in the 0229010 account projected through 2/29/2020.

[2a] Updates per Tax

[3] Annual amortization for Federal EDIT-Protected from Tax department, estimated based on ARAM method.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Supplemental Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Smith Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	47.00%	4.15%	1.50%
Equity	53.00%	10.30%	5.46%
			6.96%
Statutory Tax Rate			23.17%
Retention factor for NCUC Fee, Uncollectibles			99.63%

Annual Rider Calculation

Amortization - From Page 1, L11

Year		Beginning Balance, Page 1, L8	Federal EDIT - Protected	Federal EDIT - Unprotected, PP&E related	Federal EDIT - Unprotected, non PP&E related	NC EDIT	Deferred Revenue	Total Amortization	Ending Balance before Return	Average of Beginning and Ending Balance	EDIT Balance in Base Rates, Page 1, L1	Change in Regulatory Liability for Rider Return	Return for Rider	Rider Revenues	Rider Revenues NCUC Fee, Uncollectibles	
		(A)	(B)	(C)	(D)	(E)	(F)	(G) =(B)+(C)+(D)+[E]+[F]	(H) = (A) - (G)	(I) = ((A) + (H)) /2	(J)	(K) = (I) - (J)	(L) = (K) x After Tax WACC	(M) = (G) + (L)	(N) = (M) / Retention Factor	
Sep 20- Nov 21	1	########	(30,548)	(16,356)	(15,326)	(4,800)	(55,157)	(122,187)	(1,189,333)	($1,250,426)	(1,200,485)	($49,941)	($3,476)	(125,662)	(126,128)	
Dec 21- Nov 22	2	########	(30,548)	(16,356)	(15,326)	(4,800)	(55,157)	(122,187)	(1,067,146)	($1,128,239)	(1,200,485)	$72,246	$5,028	(117,159)	(117,593)	[1]
Dec 22- Nov 23	3	########	(30,548)	(16,356)	(15,326)	(4,800)	-	(67,029)	(1,000,117)	($1,033,631)	(1,200,485)	$166,854	$11,612	(55,418)	(55,623)	[1]
Dec 23- Nov 24	4	########	(30,548)	(16,356)	(15,326)	(4,800)	-	(67,029)	(933,087)	($966,602)	(1,200,485)	$233,883	$16,276	(50,753)	(50,941)	[1]
Dec 24- Nov 25	5	(933,087)	(30,548)	(16,356)	(15,326)	(4,800)	-	(67,029)	(866,058)	($899,572)	(1,200,485)	$300,913	$20,941	(46,088)	(46,259)	[1]

Initially Filed, Year 1 Rider Revenue ($127,633)
1,505

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by September 30th for Commission approval.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Supplemental Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL

	Deferred Revenue for Federal Tax Rate Change in account 0229010	NC Retail
1	Projected Changes in Deferred Revenue for Federal Tax Rate Change through Feb 2020	($1,923,073)

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Rebuttal

Line No.	Description	Total Company Per Books (a) (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (296,495)	$ 3,361,009	$ 544,262	$ 3,905,271
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(29,989)	851,653		851,653
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(188,002)	862,817	2,010	864,827
5	Depreciation and amortization	1,060,260	669,787	290,680	960,468		960,468
6	General taxes	153,362	102,197	1,401	103,598		103,598
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	Net income taxes	150,622	112,986	(67,481)	45,506	125,327	170,833
9	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
10	Total electric operating expenses	4,736,071	2,982,032	3,164	2,985,196	127,337	3,112,533
11	Operating income	$ 946,351	$ 675,472	$ (299,659)	$ 375,813	$ 416,925	$ 792,738
12	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 799,769 (d)	$ 10,658,819	$ 69,087 (f)	$ 10,727,906
13	Rate of return on North Carolina retail rate base		6.85%		3.53%		7.39%

-- Some totals may not foot or compute due to rounding.

Notes:
(a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

					North Carolina Retail Operations					
					Before Proposed Increase			After Proposed Increase		
Line No.	Description		Dec. 31, 2018 Amount	Pro forma Ratio	Retail Rate Base	Embedded Cost/ Return %	Operating Income	Retail Rate Base	Embedded Cost/ Return %	Operating Income
			(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)
1	Long-term debt		$ 8,108,191	47.00%	$ 5,009,645	4.11%	$ 205,768	$ 5,042,116	4.11%	$ 207,101
2	Members' equity	(a)	8,717,931	53.00%	5,649,174	3.01%	170,045	5,685,790	10.30%	585,636
3	Total		$ 16,826,122	100.00%	$ 10,658,819 (b)		$ 375,813 (c)	$ 10,727,906 (b)		792,738
4	Operating income before increase (Line 3, Column 5)									375,813
5	Additional operating income required (Line 3 minus Line 4)									416,925
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue									(309)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)									127,646
8	Additional revenue requirement									$ 544,262
9	Revenue Adjustments	(d)								$ (120,829)
10	Net Increase									$ 423,433

-- Some totals may not foot or compute due to rounding.

Notes: (a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue	Fuel Used in Electric Generation	Purchased Power	Other O&M Expense	Depreciation and Amortization	General Taxes	Income Taxes 23.1693%	Amortization of ITC	Operating Income
			(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	(52,114)	-	(172,813)
1B		Change from Application	24,093	-	-	89	-	-	5,562	-	18,443
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	3,304	-	10,955
2B		Change from Application	-	24,010	-	-	1,684	-	(5,953)	-	(19,741)
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	(13,653)	-	(45,273)
3B		Change from Application	4,882	(2,252)	-	18	-	-	1,649	-	5,467
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	534	-	1,771
4B		Change from Application	(7,341)	(5,328)	-	(27)	-	-	(460)	-	(1,526)
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	63,161	-	128,547
6B		Change from Application	-	-	-	(31)	-	-	7	-	24
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	556	-	1,843
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	(9,747)	(1,481)	(30,841)
8B		Change from Application	-	-	-	-	(661)	-	153	-	508
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	(17,857)	-	(59,213)
10B		Change from Application	-	-	-	-	(7,643)	(1,577)	2,136	-	7,084
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	(24,553)	-	(81,419)
11B		Change from Application	-	-	-	-	(9,949)	-	2,305	-	7,644
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	(304)	-	(1,007)
12B		Change from Application	-	-	-	2,930	-	-	(679)	-	(2,251)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	4,542	-	15,060
13B		Change from Application	-	-	-	(1,282)	-	(72)	314	-	1,040
14		Update benefits costs	-	-	-	(3,060)	-	-	709	-	2,351
14B		Change from Application	-	-	-	(3,298)	-	-	764	-	2,534
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	1,444	-	4,788
15B		Change from Application	-	-	-	42	-	-	(10)	-	(32)
16	*	Amortize rate case costs	-	-	-	701	-	-	(162)	-	(539)
16B		Change from Application	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	341	-	1,129
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	988	-	3,276
19B		Change from Application	-	-	-	-	(10)	-	2	-	8

Smith
Exhibit 1
Page 3

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes 23.1693% (Col. 7)	Amortization of ITC (Col. 8)	Operating Income (Col. 9)
20	* Amortize Severance Costs	-	-	-	(23,366)	-	-	5,414	-	17,952
20B	Change from Application	-	-	-	(774)	-	-	179	-	594
21	Adjust NC income taxes for rate change	-	-	-	-	-	-	(2,183)	-	2,183
22	* Synchronize interest expense with end of period rate base	-	-	-	-	-	-	123	-	(123)
22B	Change from Application	-	-	-	-	-	-	1,148	-	(1,148)
23	* Adjust cash working capital	-	-	-	-	-	-	122	-	(122)
23B	Change from Application	-	-	-	-	-	-	(27)	-	27
24	Adjust coal inventory	-	-	-	-	-	-	-	-	-
24B	Change from Application	-	-	-	-	-	-	-	-	-
25	* Adjust for credit card fees	-	-	-	5,197	-	-	(1,204)	-	(3,993)
25B	Change from Application	-	-	-	72	-	-	(17)	-	(55)
26	Adjust Depreciation for new rates	-	-	-	-	89,601	-	(20,760)	-	(68,841)
26B	Change from Application	-	-	-	-	(873)	-	202	-	671
27	Adjust vegetation management expenses	-	-	-	5,757	-	-	(1,334)	-	(4,424)
28	Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	21	-	70
29	* Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	(10,129)	-	(33,588)
29B	Change from Application	-	-	-	-	(516)	-	120	-	397
30	Adjust other revenue	(4,155)	-	-	(5)	-	-	(962)	-	(3,188)
31	Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	54	-	180
32	* Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	1,767	-	5,859
32B	Change from Application	-	-	-	-	10,381	1,032	(2,644)	-	(8,769)
33	Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	(1,144)	-	(3,794)
33B	Change from Application	-	-	-	(4,939)	-	-	1,144	-	3,794
34	* Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	(4,565)	-	(15,138)
34B	Change from Application	-	-	-	(3,496)	(3,101)	-	1,529	-	5,069
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	455	-	1,510
36	Correct Lead Lag	-	-	-	-	-	-	-	-	-
37	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ (74,904)	$ (1,481)	$ (319,441)
37B	Changes in Rebuttal	21,635	16,430	-	(10,696)	(10,688)	(617)	7,424	-	19,782
38	Total adjustments	$ (296,495)	$ (29,989)	$ (1,965)	$ (188,002)	$ 290,680	$ 1,401	$ (67,481)	$ (1,481)	$ (299,659)

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

Smith
Exhibit 1
Page 3
(continued)

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	224,927	-	224,927
1		Change from Application	-	-	-	-	-	-	-	-	(24,005)	-	(24,005)
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,258)	-	(14,258)
2B		Change from Application	-	-	-	-	-	-	-	-	25,694	-	25,694
3	*	Normalize for weather	-	-	-	-	-	-	-	-	58,926	-	58,926
3B		Change from Application	-	-	-	-	-	-	-	-	(7,116)	-	(7,116)
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,306)	-	(2,306)
4B		Change from Application	-	-	-	-	-	-	-	-	1,986	-	1,986
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,826)	-	(11,826)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,313)	(94,010)	(261,323)
6B		Change from Application	-	-	-	-	-	-	-	-	(31)	230	199
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,399)	-	(2,399)
8		Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,141	-	40,141
8B		Change from Application	-	-	-	-	-	-	-	-	(661)	-	(661)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,064	-	4,064
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,070	120,182	197,252
10B		Change from Application	(385,789)	255,631	-	20,220	(25,293)	-	-	(135,231)	(9,221)	(12,513)	(21,733)
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	105,972	29,499	135,471
11B		Change from Application	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,949)	(2,835)	(12,784)
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,311	-	1,311
12B		Change from Application	-	-	-	-	-	-	-	-	2,930	-	2,930
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,602)	-	(19,602)
13B		Change from Application	-	-	-	-	-	-	-	-	(1,354)	-	(1,354)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,060)	-	(3,060)
14B		Change from Application	-	-	-	-	-	-	-	-	(3,298)	-	(3,298)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,232)	-	(6,232)
15B		Change from Application	-	-	-	-	-	-	-	-	42	-	42
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	701	186	887
16B		Change from Application	-	-	-	-	-	-	-	-	-	(0)	(0)
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,470)	-	(1,470)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,871)	(5,821)	(7,693)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,264)	31	(4,232)
19B		Change from Application	(460)	9	-	-	-	-	-	(451)	(10)	(41)	(51)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Rebuttal

Line No.		Description	EPIS	Accum Deprec	Materials & Supplies	Working Capital	ADIT	Operating Reserves	CWIP	Rate Base	Oper Inc Rev Req Impact	R/B Rev Req Impact	Total Rev Req Impact
			(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)
20	*	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,366)	1,621	(21,745)
20B		Change from Application	-	-	-	(1,538)	356	-	-	(1,182)	(774)	(111)	(885)
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,841)	-	(2,841)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22B		Change from Application	-	-	-	-	-	-	-	-	1,494	-	1,494
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	159	(2,447)	(2,288)
23B		Change from Application	-	-	-	5,794	-	-	-	5,794	(36)	530	494
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24B		Change from Application	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,922)	(1,922)
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,197	-	5,197
25B		Change from Application	-	-	-	-	-	-	-	-	72	-	72
26		Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,601	(8,037)	81,564
26B		Change from Application	-	-	-	-	-	-	-	-	(873)	20	(853)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,757	-	5,757
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
29	*	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,717	42,594	86,311
29B		Change from Application	-	-	-	(7,227)	1,675	-	-	(5,553)	(516)	(606)	(1,122)
30		Adjust other revenue	-	-	-	-	-	-	-	-	4,150	-	4,150
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(234)	-	(234)
32	*	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,626)	(2,965)	(10,591)
32B		Change from Application	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,413	6,809	18,223
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,939	-	4,939
33B		Change from Application	-	-	-	-	-	-	-	-	(4,939)	-	(4,939)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,703	2,230	21,933
34B		Change from Application	-	-	(248)	(6,202)	1,437	-	-	(5,013)	(6,597)	(458)	(7,056)
35		Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,965)	-	(1,965)
36		Correct Lead Lag	-	-	-	(8,580)	-	-	-	(8,580)	-	(775)	(775)
37		Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 415,773	$ 83,923	$ 499,696
37B		Changes in Rebuttal	(99,196)	44,968	(21,565)	(38,667)	(12,294)	-	-	(126,755)	(25,748)	(11,658)	(37,406)
38		Total adjustments	$ 481,362	$ (57,480)	$ (172,644)	$ 853,040	$ (201,578)	$ -	$ (102,930)	$ 799,769	$ 390,025	$ 72,265	$ 462,290

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 481,362	$ 19,287,273
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(57,480)	(8,099,540)
3	Net electric plant		16,126,825	10,763,851	423,882	11,187,733
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	853,040	477,867
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(201,578)	(1,534,206)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 799,769	$ 10,658,819

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (148,421)	$ 9,908,098
2	Transmission Plant	2,746,389	1,643,263	156,769	1,800,032
3	Distribution Plant	6,944,764	6,052,263	406,303	6,458,565
4	General Plant	628,616	465,435	44,615	510,050
5	Intangible Plant	527,370	358,178	49,459	407,638
6	Subtotal	27,398,830	18,575,658	508,725	19,084,383
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 481,362	$ 19,287,273

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC

ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE

DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018

(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (19,814)	$ (4,410,572)
2	Transmission Reserve	(816,198)	(488,611)	(26,088)	(514,699)
3	Distribution Reserve	(3,235,148)	(2,819,386)	27,615	(2,791,771)
4	General Reserve	(167,536)	(124,045)	(16,254)	(140,300)
5	Intangible Reserve	(322,831)	(219,260)	(22,938)	(242,198)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (57,480)	$ (8,099,540)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Rebuttal

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Rebuttal

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	North Carolina Retail Operations: Accounting Adjustments (Col. 3)	North Carolina Retail Operations: As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)	With Rev Incr (Col. 6)
	Investor advanced funds:						
1	Operating funds per lead-lag study	238,679 (a)	160,141 (a)	(29,799) (b)	130,342	69,087 (c)	199,429
2	Unamortized Debt	47,722	32,019	-	32,019	-	32,019
3	Regulatory Assets	(781,496)	(437,291)	882,839	445,548	-	445,548
4	Other	(10,529)	(13,453)	-	(13,453)	-	(13,453)
5	Total investor advanced funds	(505,624)	(258,584)	853,040	594,456	69,087	663,542
6	Less: customer deposits	(137,271)	(116,588)	-	(116,588)	-	(116,588)
7	Total working capital investment	$ (642,895)	$ (375,172)	$ 853,040	$ 477,867	$ 69,087	$ 546,954

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Rebuttal

Smith Exhibit 1 Rebuttal

Line No.	Description	Ref #	SUMMARY OF PROPOSED REVENUE Application	February	Rebuttal	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(126,128)	(126,119)	(126,119)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(51,617)	(41,699)	(41,699)
6	Net Revenue Increase		$ 463,619	$ 413,507	$ 423,433	$ 423,433
7						

Line No.	Description	Ref #	CHANGE IN OP INCOME Application	February	Rebuttal	Total Adjs [1]		CHANGE IN RATE BASE Application	February	Rebuttal	Total Change [2]
8											
9											
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ -	$ (154,370)		$ -	$ -	$ -	$ -
11	Update fuel costs to proposed rate	NC-0200	10,955	-	10	(8,786)		-	-	-	-
12	Normalize for weather	NC-0300	(45,273)	6,892	-	(39,806)		-	-	-	-
13	Annualize revenues for customer growth	NC-0400	1,771	(6,801)	-	246		-	-	-	-
14	Eliminate unbilled revenues	NC-0500	9,086	-	-	9,086		-	-	-	-
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	-	128,571		(1,037,885)	-	-	(1,037,885)
16	Adjust O&M for executive compensation	NC-0700	1,843	-	-	1,843		-	-	-	-
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	-	(30,333)		-	-	-	-
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	-	(3,122)		-	-	-	-
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	7,494	(804)	(52,129)		1,326,826	(140,022)	15,751	1,191,596
20	Amortize deferred environmental costs	NC-1100	(81,419)	(302)	-	(73,775)		325,675	1,207	-	295,100
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	-	(2,245)	(3,259)		-	-	-	-
22	Normalize O&M labor expenses	NC-1300	15,060	347	-	16,100		-	-	-	-
23	Update benefits costs	NC-1400	2,351	-	-	4,885		-	-	-	-
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	-	4,756		-	-	-	-
25	Amortize rate case costs	NC-1600	(539)	-	-	(539)		2,051	-	-	2,051
26	Adjust aviation expenses	NC-1700	1,129	-	-	1,129		-	-	-	-
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	-	1,438		(64,423)	-	-	(64,423)
28	Adjust for Merger Related Costs	NC-1900	3,276	8	-	3,284		347	(451)	-	(104)
29	Amortize Severance Costs	NC-2000	17,952	(243)	-	18,547		17,899	486	-	16,717
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	-	2,183		-	-	-	-
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(387)	(484)	(1,271)		-	-	-	-
32	Adjust cash working capital	NC-2300	(122)	14	1	(95)		(27,013)	3,003	(74)	(21,219)
33	Adjust coal inventory	NC-2400	-	-	-	-		9,641	-	-	(11,603)
34	Adjust for credit card fees	NC-2500	(3,993)	5	29	(4,048)		-	-	-	-
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	-	(68,170)		(88,728)	-	-	(88,728)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	-	(4,424)		-	-	-	-
37	Adjust reserve for end of life nuclear costs	NC-2800	70	-	-	70		-	-	-	-
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	1,031	-	(33,192)		470,238	(14,429)	-	464,685
39	Adjust other revenue	NC-3000	(3,188)	-	-	(3,188)		-	-	-	-
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	-	180		-	-	-	-
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	(181)	(8,864)	(2,910)		(32,730)	77,025	-	42,550
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-	-		-	-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	285	3,518	(10,069)		24,624	(817)	(1,664)	19,611
44	Adjust Purchased Power	NC-3500	1,510	-	-	1,510		-	-	-	-
45	Correct Lead Lag	NC-3600	-	-	-	-		-	(8,580)	-	(8,580)
46											
47		Adjustments	$ (319,441)	$ 8,160	$ (8,838)	$ (299,659)		$ 926,524	$ (82,578)	$ 14,013	$ 799,769
48											
49	Operating income	[3]	675,472	675,472	675,472	675,472	Rate base [4]	9,859,050	9,859,050	9,859,050	9,859,050
50	Total Adjustments		(319,441)	(290,821)	(299,659)	(299,659)	Total Adjustments	926,524	785,755	799,769	799,769
51	Adjusted Net Operating Income		356,031	384,651	375,813	375,813	Adjusted Rate Base	10,785,574	10,644,806	10,658,819	10,658,819
52											
53	Revenue Requirement Impact		415,773	(10,621)	11,503	390,025	9.0357%	83,718	(7,462)	1,266	72,265
			415,773	378,522	390,025	390,025		83,718	70,999	72,265	72,265

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0200
Supplemental (D)
Rebuttal Update

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts fuel expense,depreciation expense and income taxes for fuel clause expense during the test period to match the fuel clause revenues derived from the fuel factor approved by the Commission in Docket No. E-2, Sub 1173. By matching the expenses to the revenue, this adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related expenses that are recoverable through the fuel clause. This adjustment also eliminates the deferred fuel expense from the test period.

The impact to fuel and fuel related expenses is determined as follows:
1. The total fuel clause expense allocated in cost of service is eliminated from the test period.

2. The pro forma fuel clause expense is calculated by multiplying the NC Retail kWh sales for the test period by the most recent approved fuel rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

November Update
Revised for approved rates under Docket E2 Sub 1204

December Update
Removed effect of approved rates under Docket E2 Sub 1204. Will update along side Revenue impact in NC-0100 for Supplemental filing

January Update
Revised for approved rates under Docket E2 Sub 1204 and change in treatment of Catalyst Depreciation

Rebuttal
Corrected forumla error on NC-0202-2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0200
Supplemental (D)
Rebuttal Update

Line No.	Description	Source	Total NC Retail Rebuttal	Total NC Retail Change
1			Rebuttal	Change
2	**Pro Formas Impacting Income Statement Line Items**			
3				
4	Electric operating revenue		$ -	$ -
5				
6	Electric operating expenses:			
7	Operation and maintenance			
8	Fuel used in electric generation	NC-0201	11,436	24,010
9	Purchased power		-	-
10	Other operation and maintenance expense		-	-
11	Depreciation and amortization	NC-0201	-	1,684
12	General taxes		-	-
13	Interest on customer deposits		-	-
14	Income taxes	NC-0201	(2,650)	(5,953)
15	Amortization of investment tax credit		-	-
16				
17	Total electric operating expenses	Sum L8 through L15	8,786	19,741
18				
19	Operating income	L4 - L17	$ (8,786)	$ (19,741)
20				
21	Notes:			
22	Revenue: positive number increases revenue / negative number decreases revenue			
23	Expense: positive number increases expense / negative number decreases expense			
24				
25				
26	**Pro Formas Impacting Rate Base Line Items**			
27				
28	Electric plant in service			
29	Accumulated depreciation and amortization			
30	Electric plant in service, net	Sum L28 through L29	-	-
31				
32	Add:			
33	Materials and supplies			
34	Working capital investment			
35				
36				
37	Less:			
38	Accumulated deferred taxes			
39	Operating reserves			
40				
41				
42	Construction work in progress			
43				
44	Total impact to rate base	Sum L30 through L42	$ -	$ -
45				
46	Note:			
47	Rate Base: positive number increases rate base / negative number decreases rate base			

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0201
Supplemental (D)
Rebuttal Update

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	SI NCSI	Area Service Lighting NCALS	Sports Field Lighting Service NCSFL	Street Lighting Service NCSLS	Street Lighting Service NCSLR	Traffic Service Signal NCTSS		Total NC Retail	
1	Fuel Clause Expense and Deferred Fuel Expense Allocated in Per Books Cost of Service													
2	Remove fuel included in system average fuel costs												$ 729,766	[1]
3	Remove purchased power included in system average fuel costs - demand												41,843	[2]
4	Remove purchased power included in system average fuel costs - energy												322,567	[3]
5	Remove reagents & by-products included in system average fuel costs												62,778	[4]
6	Remove catalyst depreciation included in system average fuel costs												-	[5]
7	Remove 0557980 - Retail Deferred Fuel Expenses												(273,901)	[6]
8	Total Fuel Clause Expense Allocated in COS and Retail Deferred Fuel Expense (Sum L2 through L7)												$ 883,053	
9														
10	Fuel Clause Expense to Add (Based on Approved Fuel Rates)													
11	Average fuel rate billed in test period	2.238	2.188	2.305	2.449	2.305	1.780	1.780	1.780	1.780	2.188	[7]		
12	Increment in Fuel Filing, excluding Reg Fee & EMF (Cents/kWh) (L13 - L11)	0.088	0.312	0.151	(0.395)	0.151	0.437	0.437	0.437	0.437	0.030			
13	Approved Base Fuel Factor (Cents/kWh), excluding Regulatory Fee	2.326	2.499	2.456	2.054	2.456	2.217	2.217	2.217	2.217	2.217	[7]		
14														
15	NC Retail kWh actual sales - 12 months ended December 2018	16,666,046,589	1,982,596,401	11,178,964,878	8,457,791,022	43,075,313	267,795,639	1,134,908	85,107,971		4,754,792	[8]	38,687,267,513	[8]
16														
17	Adjusted Fuel Clause Expenses (L15 x (L13 / 100,000))	$ 387,652	$ 49,545	$ 274,555	$ 173,723	$ 1,058	$ 5,937	$ 25	$ 1,887	$ -	$ 105		894,488	
18														
19	Impact to fuel (-L2 + L17)												$ 164,722	
20														
21	Impact to purchased power (-L3 - L4 - L7)												$ (90,509)	
22														
23	Impact to Energy Related O&M (-L5)												$ (62,778)	
24														
25	Impact to depreciation and amortization (-L6)												$ -	
26														
27	Taxable income (-L19 - L21 - L23 - L25)												$ (11,436)	
28	Statutory tax rate												23.1693%	[9]
29	Impact to income taxes (L27 x L28)												$ (2,650)	
30	Impact to operating income (L27 - L29)												$ (8,786)	

[1] E-1 Item 45A, Cost of Service Factor E1All
[2] E-1 Item 45A, Cost of Service Factor E1All
[3] E-1 Item 45A, Cost of Service Factor E1All
[4] E-1 Item 45A, Cost of Service Factor E1All
[5] Catalyst adjusted through Depreciation proformas NC-0800 and NC-2600
[6] E-1 Item 45A, Cost of Service, Direct Assigned to NC Retail then Allocated using Factor E2ALL
[7] NC-0202 - NC Billed Fuel Factors, Line 5 and Line 8
[8] NC-0404 - NC Billed KWH Sales
[9] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202
Supplemental (D)
Rebuttal Update

NC Billed Fuel Factors (with EMF and EMF Interest Increment/Decrement for approved cost factors)

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	Area Service Lighting	Sports Field Lighting Service	Street Lighting Service	Traffic Service Signal		
1											
2	Approved net fuel and fuel related costs factors (including EMF)										
3	January 2018 through November 2018 fuel rate billed	2.179	2.121	2.258	2.417	1.657	1.657	1.657	2.121	[1]	
4	December 2018 fuel rate billed	2.886	2.919	2.820	2.795	3.136	3.136	3.136	2.919	[2]	
5	Average fuel rate billed in test period (Monthly Weighted Avg L3 and L4)	2.238	2.188	2.305	2.449	1.780	1.780	1.780	2.188		
6											
7	Approved net fuel and fuel related costs factors (excluding EMF)										
8	Approved net fuel and fuel related costs factors (pro forma fuel factor)	2.326	2.499	2.456	2.054	2.217	2.217	2.217	2.217	[3]	Incorrect link
9											
10	Increase (Decrease) in fuel rate (L8 - L5)	0.088	0.312	0.151	(0.395)	0.437	0.437	0.437	0.030		

[1] NC-0202-1 - Docket No. E-2, Sub 1146, Appendix A, Column F
[2] NC-0202-2 - Docket No. E-2, Sub 1173, Appendix A, Column F
[3] NC-0202-3- Approved rates in Docket No. E-2, Sub 1173

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202-1
Supplemental (D)
Rebuttal Update

Approved Fuel Rates for December 2017 through November 2018

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC	)	ORDER APPROVING
Pursuant to G.S. 62-133.2 and	)	FUEL CHARGE
NCUC Rule R8-55 Relating to Fuel	)	ADJUSTMENT
and Fuel-Related Charge Adjustments	)	
for Electric Utilities	)	

HEARD: Tuesday, September 19, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	3.013	(0.834)	2.179	-	-	2.179
Small General Service	3.001	(0.880)	2.121	-	-	2.121
Medium General Service	2.921	(0.565)	2.356	(0.084)	(0.014)	2.258
Large General Service	2.958	(0.541)	2.417	-	-	2.417
Lighting	3.655	(1.998)	1.657	-	-	1.657

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202-2
Supplemental (D)
Rebuttal Update

Approved Fuel Rates for December 2018 through November 2019

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1173

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, September 18, 2018, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	1.993	0.318	2.311	0.575	-	2.886
Small General Service	2.088	0.468	2.556	0.363	-	2.919
Medium General Service	2.431	0.046	2.477	0.343	-	2.820
Large General Service	2.253	(0.496)	1.757	1.038	-	2.795
Lighting	0.596	1.655	2.251	0.885	-	3.136

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0202-3
Supplemental (D)
Rebuttal Update

Approved Fuel Rates for December 2019 through November 2020

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Fuel & Fuel Related Costs, Excl. Purch Capacity	2.188	2.344	2.333	1.975	2.216
Renewable & QF Purch Capacity	0.138	0.155	0.123	0.079	0.001
Total Adjusted Fuel and Fuel Related Costs	2.326	2.499	2.456	2.054	2.217
EMF	0.373	0.198	0.218	0.648	0.530
EMF Interest	-	-	-	-	-
Net Proposed Fuel and Fuel Related Cost Factors	2.699	2.697	2.674	2.702	2.747

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update fuel costs to approved rate
For the test period ended December 31, 2018

NC-0203
Supplemental (D)
Rebuttal Update

Monthly Fuel Filing-System Average Fuel Costs for 12 Months Ended December 2018

As of 1/30/19 **Schedule 2**

Duke Energy Progress
Details of Fuel and Fuel-Related Costs

Description	Docket No. E-2, Sub 1164 December 2018	12 Months Ended December 2018
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 34,453,367	$ 307,900,875
0501310 fuel oil consumed - steam	1,404,117	10,490,738
Total Steam Generation - Account 501	35,857,484	318,391,613
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	16,323,865	184,163,880
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	18,456,887	185,884,718
0547000 natural gas consumed - Combined Cycle	54,365,629	649,230,756
0547106 biogas consumed - Combined Cycle	44,669	179,596
0547200 fuel oil consumed	1,051,520	63,615,887
Total Other Generation - Account 547	73,918,705	898,910,957
Reagents		
Catalyst Depreciation	131,225	2,737,099
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	2,048,497	17,128,899
Total Reagents	2,179,721	19,865,998
By-products		
Net proceeds from sale of by-products	72,561,504	85,600,935
Total By-products	72,561,504	85,600,935
Total Fossil and Nuclear Fuel Expenses		
Included in Base Fuel Component	200,841,279	1,506,933,383
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	636,198	26,295,307
Capacity component of purchased power (renewables)	1,413,993	42,177,805
Fuel and fuel-related component of purchased power	28,818,399	527,852,191
Total Purchased Power and Net Interchange - Account 555	30,868,590	596,325,303
Less fuel and fuel-related costs recovered through intersystem sales - Account 447	28,778,413	207,269,136
Total Fuel and Fuel-Related Costs	$ 202,931,456	$ 1,895,989,550

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018

NC-1000
Rebuttal

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts depreciation expense, general taxes, income taxes, electric plant in service, accumulated depreciation, working capital investment, accumulated deferred income taxes and construction work in progress to reflect net additions to plant in service.

The impact to operating income is determined as follows:
The adjustment to depreciation expense reflects a full year's level of depreciation on net additions to plant in service by multiplying the projected additions to net electric plant by depreciation rates based on the new depreciation study.

The adjustment to general taxes reflects estimated annual property tax expense related to the net additions to plant in service. Property taxes are estimated by multiplying the projected net additions to electric plant by a combined North Carolina and South Carolina property tax rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

The impact to rate base is determined as follows:
The adjustment to electric plant in service reflects projected updates to electric plant in service through February 2020.
The adjustment to accumulated depreciation reflects projected updates to the accumulated depreciation balance through February 2020 and annualized depreciation expense based on forecasted February 2020 electric plant in service balances.
The adjustment to working capital investments reflects projected updates to the unrecovered net book value of retired meters regulatory asset through February 2020.
The adjustment to accumulated deferred income taxes reflects the impacts of projected bonus depreciation on gross plant additions through February 2020.
The adjustment to construction work in progress is to remove the balance related to Asheville CC that was included in rate base in the last rate case. Asheville CC is forecasted to go in service during the capital cutoff period.

October Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through October 2019.
Corrected references to Duke Energy Carolinas in footnotes

November Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through November 2019. Updated forecasted DSDR numbers on NC-1007, NC-1008, and NC-1009 based on revised DSDR asset balances.

December Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through December 2019.

January Update
Updated NC-1005, NC-1008, NC-1009 and NC-1010 for actuals through January 2020.

February Update
Updated NC-1005, NC-1007, NC-1008, NC-1009 and NC-1010 for actuals through February 2020. NC-1008 been updated to include Asheville CC Unit 8, which expected in service in March 2020.
Updated NC-1008 to account for reclass Vanderbuilt W Asheville 115kV recondutor project

Rebuttal Update
Update NC-1008 for new Asheville CC plant in service. Unit 8 went into service April 5, 2020.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1000
Rebuttal

Line No.	Description	Source	Total NC Retail Rebuttal	Total NC Retail Application	Change
1			Rebuttal	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization	NC-1001	62,826	70,469	(7,643)
12	General taxes	NC-1001	5,023	6,600	(1,577)
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1001	(15,720)	(17,857)	2,136
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	52,129	59,213	(7,084)
18					
19	Operating income	L4 - L17	$ (52,129)	$ (59,213)	$ 7,084
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-1001	$ 1,460,147	$ 1,845,936	$ (385,789)
29	Accumulated depreciation and amortization	NC-1001	(127,842)	(383,473)	255,631
30	Electric plant in service, net	Sum L28 through L29	$ 1,332,305	$ 1,462,463	$ (130,158)
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment	NC-1001	18,763	(1,458)	20,220
35					
36					
37	Less:				
38	Accumulated deferred taxes	NC-1001	(56,542)	(31,249)	(25,293)
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress	NC-1001	(102,930)	(102,930)	-
43					
44	Total impact to rate base	Sum L30 through L42	$ 1,191,596	$ 1,326,826	$ (135,231)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC | NC-1001
Docket No. E-2, Sub 1219 | Rebuttal
Adjust for post test year additions to plant in service | Page 1 of 2
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Electric Plant	Depr Rate	Depr.	Total System	NC Retail Allocation	Total NC Retail
1	Impact to Rate Base Line Items						
2	Total net additions to electric plant:						
3	Fossil	$ (192,169) [1]	5.33% [2]	$ (10,243)			
4	Production Direct Assignments - NC	134 [1]	5.33% [2]	7			
5	Direct Assignments - WHS	(4,614) [1]	5.33% [2]	(246)			
6	Nuclear	330,066 [1]	3.31% [2]	10,925			
7	Production Direct Assignments - NC	2,934 [1]	3.31% [2]	97			
8	Direct Assignments - SC	352 [1]	3.31% [2]	12			
9	Direct Assignments - WHS	368 [1]	3.31% [2]	12			
10	Hydro	13,247 [1]	3.70% [2]	490			
11	Other Production	856,677 [1]	5.08% [2]	43,519			
12	Direct Assignments - WHS	(300) [1]	5.08% [2]	(15)			
13	Transmission	264,107 [1]	2.23% [2]	5,890			
14	Distribution	692,509 [1]	2.39% [18]	16,551			
15	Distribution - AMR Meter Retirements	(61,039) [17]					
16	General	77,411 [1]	5.74% [2]	4,443			
17	Intangible	105,665 [1]	[13]	20,607			
18	Total net additions to depreciable electric plant (L3 through L17)	$ 2,085,348		$ 92,050			
19							
20	Summary of impacts to rate base						
21	Net additions to total electric plant in service:						
22	Production Plant				$ 1,007,819 [1]	61.5278% [4]	$ 620,089
23	Production Direct Assignments - NC				3,069 [1]	100.0000%	3,069
24	Direct Assignments - SC				352 [1]	0.0000%	-
25	Direct Assignments - WHS				(4,543) [1]	0.0000%	-
26	Transmission plant				264,105 [1]	59.6699% [5]	157,591
27	Distribution plant				631,470 [1]	87.1486% [6]	550,317
28	General plant				77,411 [1]	74.0412% [7]	57,316
29	Intangible plant				105,665 [1]	67.9178% [8]	71,765
30	Impact to electric plant in service (Sum L22 through L29)				$ 2,085,348		$ 1,460,147
31							
32	Accumulated depreciation & amortization:						
33	Production Plant				$ (78,079) [3]	61.5278% [4]	$ (48,040)
34	Production Direct Assignments - NC				27,632 [3]	100.0000%	27,632
35	Direct Assignments - SC				2,714 [3]	0.0000%	-
36	Direct Assignments - WHS				1,625 [3]	0.0000%	-
37	Transmission				(32,884) [3]	59.6699% [5]	(19,622)
38	Distribution				(8,550) [3]	87.1486% [6]	(7,451)
39	General				(19,522) [3]	74.0412% [7]	(14,455)
40	Intangible				(65,987) [3]	67.9178% [8]	(44,817)
41	Adjustment to accumulated depreciation & amortization (Sum L33 through L40)				$ (173,051)		$ (106,753)
42	Additional adjustment for Feb. 29, 2020 annualization				(31,950) [14]		(21,089) [14]
43	Impact to accumulated depreciation and amortization (L41 + L42)				$ (205,002)		$ (127,842)
44							
45	Net electric plant:						
46	Production (L22 + L33)				$ 929,740		$ 572,049
47	Direct Assignments - NC (L23 + L34)				30,701		30,701
48	Direct Assignments - SC (L24 + L35)				3,066		-
49	Direct Assignments - WHS (L25 + L36)				(2,918)		-
50	Transmission (L26 + L37)				231,221		137,969
51	Distribution (L27 + L38)				622,920		542,866
52	General (L28 + L39)				57,889		42,862
53	Intangible (L29 + L40)				39,678		26,949
54	Adjustment to net plant (Sum L46 through L53)				$ 1,912,296		$ 1,353,394
55	Additional adjustment for Feb. 29, 2020 annualization				(31,950) [14]		(21,089) [14]
56	Total net plant (L54 + L55)				$ 1,880,346		$ 1,332,305
57							
58	Working capital investment:						
59	Net change in NC Unrecovered NBV of Retired Meters				$ 18,763 [15]		$ 18,763 [15]
60	Impact to working capital investment (L59)				$ 18,763		$ 18,763
61							
62	Accumulated deferred income tax:						
63	Resulting from additional bonus depreciation:						
64	Production				$ (73,552) [9]	61.5278% [4]	$ (45,255)
65	Transmission				(2,508) [9]	59.6699% [5]	(1,496)
66	Distribution				(1,474) [9]	87.1486% [6]	(1,285)
67	General				(356) [9]	74.0412% [7]	(264)
68	Intangible				(5,734) [9]	67.9178% [8]	(3,895)
69	Adjustment resulting from additional bonus depreciation (Sum L64 through L68)				$ (83,625)		$ (52,195)
70	Adjustment resulting from Meter working capital investment				$ (4,347) [15]		$ (4,347) [15]
71	Impact to accumulated deferred income tax (L69 + L70)				$ (87,972)		$ (56,542)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Total System	NC Retail Allocation	Total NC Retail
72				
73	Construction work in progress:			
74	Remove Asheville CWIP in rate base	$ (169,850) [16]		$ (102,930) [16]
75	Impact to construction work in progress	$ (169,850)		$ (102,930)
76				
77	Impact to rate base (L56 + L60 + L71 + L75)	$ 1,641,287		$ 1,191,596
78				
79	Impact to Income Statement Line Items			
80	Depreciation and amortization:			
81	Production (L3 + L6 + L10 + L11)	$ 44,692	61.5278% [4]	$ 27,498
82	Production Direct Assignments - NC (L4 + L7)	104	100.0000%	104
83	Direct Assignments - SC (L8)	12	0.0000%	-
84	Direct Assignments - WHS (L5 + L9 + L12)	(249)	0.0000%	-
85	Transmission (L13)	5,890	59.6699% [5]	3,514
86	Distribution (L14)	16,551	87.1486% [6]	14,424
87	General (L16)	4,443	74.0412% [7]	3,290
88	Intangible (L17)	20,607	67.9178% [8]	13,996
89	Impact to depreciation and amortization (Sum L81 through L88)	$ 92,050		$ 62,826
90				
91	General taxes:			
92	Average property tax rate - North Carolina	0.22148% [10]		
93	Average property tax rate - South Carolina	0.14111% [10]		
94	Average property tax rate-Combined NC and SC (L92 + L93)	0.36259%		
95				
96	Production - Excluding Solar (((Sum L3 through Sum L11) - NC-1008 Line 39) x L94)	$ 3,654	61.5278% [4]	$ 2,248
97	Production - Solar	(0) [12]	61.5278% [4]	(0)
98	Transmission (L13 x L94)	958	59.6699% [5]	571
99	Distribution (L14 + L15 x L94)	2,290	87.1486% [6]	1,995
100	General (L16 x L94)	281	74.0412% [7]	208
101	Impact to general taxes (Sum L96 through L100)	$ 7,182		$ 5,023
102				
103	Taxable income (-L89 - L101)	$ (99,232)		$ (67,849)
104	Statutory tax rate	23.1693% [11]		23.1693% [11]
105	Impact to income taxes (L103 x L104)	$ (22,991)		$ (15,720)
106				
107	Impact to operating income (L103 - L105)	$ (76,241)		$ (52,129)

[1] NC-1002 - Net Plant Adds
[2] NC-2602 - Comparison of Current and Proposed Depreciation as of December 31, 2018, Proposed Rate Column
[3] NC-1003 - Accumulated Depreciation
[4] Allocation Factor - DPALL
[5] Allocation Factor - DTALL
[6] Allocation Factor - RB PLT O DI
[7] Allocation Factor - RB PLT O GN
[8] Allocation Factor - PTDG
[9] NC-1004 - Accumulated Deferred Income Taxes Calculation
[10] NC-0901 - Annualize property taxes on year end plant balances, Line 16
[11] NC-0104 - 2019 Calculation of Tax Rates - Composite Tax Rate, Line 10
[12] NC-1008 - Plant in Service Balances - Solar additions are included at 20% of total based on property tax exclusion for solar assets per Tax Department.
[13] Updated annualized depreciation on intangible additions per Asset Accounting.
[14] NC-1006 - Accumulated Depreciation Annualization Adjustment
[15] NC-1005 - NC Unrecovered Net Book Value of Retired Meters, Line 24 and Line 28
[16] NC-1011 - Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142
[17] AMR meter retirements, from Asset Accounting, should not have an impact on depreciation expense, recovering retired AMR meters in reg asset.
[18] Distribution composite rate without AMR meter line from the proposed 2018 Depreciation Study

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1002
Rebuttal

Net Plant Adds

		Total System		
Line No.	Item	Actual [1] Net Change through 2/29/2020	Adjustments	Total Adjusted Net Change Plant in Service
1	Electric Plant in Service:			
2	Steam plant	$ (169,407)	$ (22,762) [2]	$ (192,169)
3	Direct Assignments - NC	134		134
4	Direct Assignments - WHS	(4,614)		(4,614)
5	Nuclear plant	405,547	(75,480) [2]	330,066
6	Direct Assignments - NC	2,934		2,934
7	Direct Assignments - SC	352		352
8	Direct Assignments - WHS	368		368
9	Hydro plant	13,247		13,247
10	Other production plant	856,677		856,677
11	Direct Assignments - WHS	(300)		(300)
12	Transmission plant	264,107	- [3]	264,107
13	Distribution plant	662,390	(30,921) [3]	631,470
14	General plant	84,110	(6,699) [3]	77,411
15	Intangible plant	105,665	- [3]	105,665
16	Total Electric Plant in Service (Sum L2 through L15)	$ 2,221,210	$ (135,862)	$ 2,085,348
17				
18	COS Eletric Plant in Service			
19	Production Plant	$ 1,106,061	$ (98,242) [2]	$ 1,007,819
20	Direct Assignments - NC	3,069		3,069
21	Direct Assignments - SC	352		352
22	Direct Assignments - WHS	(4,543)		(4,543)
23	Transmission plant	264,105	- [3]	264,105
24	Distribution plant	662,390	(30,921) [3]	631,470
25	General plant	84,110	(6,699) [3]	77,411
26	Intangible plant	105,665	- [3]	105,665
27	Total COS Electric Plant in Service (Sum L19 through L26)	$ 2,221,210	$ (135,862)	$ 2,085,348
28				
29	Electric Plant in Service recovered in riders included above:			
30	JAAR - Steam plant	$ 22,762	$ 22,762 [2]	
31	JAAR - Nuclear plant	75,480	75,480 [2]	
32	JAAR - Acquisition Adjustment	0	0 [2]	
33	DSDR - Transmission	-	- [3]	
34	DSDR - Distribution	30,921	30,921 [3]	
35	DSDR - General plant	6,699	6,699 [3]	
36	DSDR - Intangibles	-	- [3]	
37	Total EPIS recovered in riders (Sum L30 through L35)	$ 135,862	$ 135,862	

[1] NC-1008 - Plant in Service Balances
[2] Amounts related to balances that are collected through the JAAR and should be excluded for purposes of this analysis.
[3] Amounts related to balances that are collected through the DSDR rider and should be excluded for purposes of this analysis.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1003
Rebuttal

Accumulated Depreciation

Line No.	Item	Total System: Actual [1] Net Change through 2/29/2020	Total System: Adjustments		Total System: Total Adjusted Net Change Accumulated Depreciation
1	COS Accumulated Depreciation:				
2	Production Plant	$ (133,156)	55,077	[2]	$ (78,079)
3	Direct Assignments - NC	27,632			27,632
4	Direct Assignments - SC	2,714			2,714
5	Direct Assignments - WHS	1,625			1,625
6	Transmission plant	(32,898)	13	[3]	(32,884)
7	Distribution plant	(14,758)	6,208	[3]	(8,550)
8	General plant	(20,814)	1,292	[3]	(19,522)
9	Intangible plant	(66,374)	387	[3]	(65,987)
10	Total COS Accumulated Depreciation (Sum L2 through L9)	$ (236,029)	$ 62,977		$ (173,051)
11					
12	Accumulated Depreciation recovered in riders included above:				
13	JAAR - Steam plant	$ (6,349)	$ (6,349)	[2]	
14	JAAR - Nuclear plant	(33,843)	(33,843)	[2]	
15	JAAR - Acquisition Adjustment	(14,885)	(14,885)	[2]	
16	DSDR - Transmission	(13)	(13)	[3]	
17	DSDR - Distribution	(6,208)	(6,208)	[3]	
18	DSDR - General plant	(1,292)	(1,292)	[3]	
19	DSDR - Intangibles	(387)	(387)	[3]	
20	Total Accum Depr recovered in riders (Sum L13 through L19)	$ (62,977)	$ (62,977)		

[1] NC-1009 - Accumulated Depreciation Balances
[2] Amounts related to balances that are collected through the JAAR and should be excluded for purposes of this analysis.
[3] Amounts related to balances that are collected through the DSDR rider and should be excluded for purposes of this analysis.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1004
Rebuttal

Accumulated Deferred Income Taxes Calculation

Line No.	Item		Total System Forecasted Bonus Depreciation through 2/29/2020	
1	Bonus Depreciation			
2	Steam plant	$	69,762	[1]
3	Nuclear plant		59,790	[1]
4	Hydro plant		292	[1]
5	Other production plant		187,609	[1]
6	Transmission plant		10,824	[1]
7	Distribution plant		6,363	[1]
8	General plant		1,538	[1]
9	Intangible plant		24,750	[1]
10	Total Accumulated Depreciation (Sum L2 through L9)	$	360,929	
11				
12	Statutory tax rate		23.1693%	[2]
13				
14	Accumulated deferred income taxes (resulting from additional bonus depreciation):			
15	Steam plant (-L2 x L12)	$	(16,163)	
16	Nuclear plant (-L3 x L12)		(13,853)	
17	Hydro plant (-L4 x L12)		(68)	
18	Other production plant (-L5 x L12)		(43,468)	
19	Transmission plant (-L6 x L12)		(2,508)	
20	Distribution plant (-L7 x L12)		(1,474)	
21	General plant (-L8 x L12)		(356)	
22	Intangible plant (-L9 x L12)		(5,734)	
23	Impact to accumulated deferred income taxes (Sum L15 through L22)	$	(83,625)	

[1] Forecasted amounts provided by Duke Energy Progress - Tax Department
[2] NC-0104 - 2019 Calculation of Tax Rates - Composite Tax Rate, Line 10

Duke Energy Progress, LLC | NC-1005
Docket No. E-2, Sub 1219 | Rebuttal
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018

NC Unrecovered Net Book Value of Retired Meters

Line No.	Description	Total NC Retail	
1	NC Unrecovered NBV of Retired Meter Reg Asset Balance:		
2	Dec 2018	$ 11,503,875	[1]
3	Jan 2019	11,503,875	[1]
4	Feb 2019	11,503,875	[1]
5	Mar 2019	17,441,466	[1]
6	Apr 2019	17,441,466	[1]
7	May 2019	17,441,466	[1]
8	Jun 2019	21,619,389	[1]
9	Jul 2019	21,619,389	[1]
10	Aug 2019	21,619,389	[1]
11	Sep 2019	23,513,015	[1]
12	Oct 2019	23,513,015	[1]
13	Nov 2019	23,513,015	[1]
14	Dec 2019	27,790,778	[1]
15	Jan 2020	27,790,778	[1]
16	Feb 2020	30,266,524	[1]
17			
18	Amortization period per 2016 Depreciation Study - Months (10 yrs x 12)	120	[2]
19			
20	Date new depreciation rates effective	3/16/2018	
21	Number of periods left to amortize at 12/31/2018 (L18 - 9.5)	110.5	
22			
23	Monthly amortization based on regulatory asset balance at 12/31/2018 ((L2 / L21)	$ 104,107	
24			
25	Forecasted net change through 02/29/2020 (L15 - L2)	18,762,650	
26			
27	Statutory tax rate	23.1693%	[3]
28			
29	Impact to accumulated deferred income taxes (-L25 x L27)	$ (4,347,175)	

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Remaining life of Meters to be replaced during the AMI deployment settled in the 2016 Depreciation Study
[3] NC-0104 - 2019 Calculation of Tax Rates - Composite Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1006
Rebuttal

Accumulated Depreciation Annualization Adjustment

Line No.	Item	Total System		Adjustments		Total Adjusted System	NC Retail Allocation		Total NC Retail
1	Accumulated Depreciation								
2	Production (Line 5 + Line 9 + Line 13 + Line 19) - L3	$ (27,235)	[1]	$ 604	[2]	$ (26,631)	61.5278%	[4]	$ (16,386)
3	Production Direct assigned to NC (Line 4 + Line 18)	(18)	[1]			(18)	100.0000%		(18)
4	Production Direct assigned to WHS (Line 4 + Line 18)	187	[1]			187	0.0000%		-
4	Transmission (Line 25) - L5	(3,019)	[1]	-		(3,019)	59.6699%	[5]	(1,801)
5	Transmission Direct assigned to Wholesale (Line 24)	5	[1]			5	0.0000%		-
6	Distribution (Line 31) - L7	(8,178)	[1]	54		(8,124)	87.1486%	[6]	(7,080)
7	Distribution Direct assigned to Wholesale (Line 30)	0	[1]			0	0.0000%		-
8	General (Line 46) - L9	5,743	[1]	$ 125		5,868	74.0412%	[7]	4,345
9	General Direct assigned to Wholesale (Line 44)	(0)	[1]			(0)	0.0000%		-
10	Intangible (Line 48)	-	[1]	$ (218)		(218)	67.9178%	[8]	(148)
11	Impact to accum. deprec. (Sum L2 through L10)	$ (32,514)		$ 564		$ (31,950)			$ (21,089)
12									
13	Accumulated Depreciation recovered in riders included above:								
14	JAAR - Steam plant	$ 16	[1]	$ 16	[2]				
15	JAAR - Nuclear plant	(620)	[1]	(620)	[2]				
16	DSDR - Transmission	-	[1]	-	[3]				
17	DSDR - Distribution	(54)	[1]	(54)	[3]				
18	DSDR - General plant	(125)	[1]	(125)	[3]				
19	DSDR - Intangibles	218	[1]	218	[3]				
20	Total Accum Depr recovered in riders (Sum L14 through L18)	$ (564)		$ (564)					

[1] NC-1007 - Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense at February 29, 2020
[2] Amounts related to balances forecasted to flow through the JAAR and should be excluded for purposes of this analysis.
[3] Amounts related to balances forecasted to flow through the DSDR rider and should be excluded for purposes of this analysis.
[4] Allocation Factor - DPALL
[5] Allocation Factor - DTALL
[6] Allocation Factor - RB PLT O DI
[7] Allocation Factor - RB PLT O GN
[8] Allocation Factor - PTDG

Duke Energy Progress, LLC NC-1007
Docket No. E-2, Sub 1219 Rebuttal
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense at Feb. 29, 2020

Line No.	Function		Plant in Service [8] 2/29/2020	Depr Rate [9]		Current Rates Calculated Accrual		12ME Depr Booked [10]		Difference
1	STEAM: [1]									
2	STEAM PLANT	$	3,848,841	3.75%	$	144,332	$	154,170	$	(9,838)
3	LAND RIGHTS - STEAM		23,885	0.30%		72		30		41
4	NC IMPAIRMENT - STEAM		(10,393)	3.75%		(390)		(415)		25
5	WHS IMPAIRMENT - STEAM		(4,666)	3.75%		(175)		-		(175)
6		$	3,857,667		$	143,838	$	153,786	$	(9,947)
7	NUCLEAR: [1]									
8	NUCLEAR PLANT	$	10,169,379	2.80%	$	284,743	$	267,743	$	17,000
9	LAND RIGHTS - NUCLEAR		74,790	1.20%		897		677		221
10		$	10,244,169		$	285,640	$	268,420	$	17,220
11	HYDRO: [1]									
12	HYDRAULIC PLANT	$	154,358	3.47%	$	5,356	$	5,066	$	290
13	LAND RIGHTS - HYDRO		2,829	2.52%		71		4		68
14		$	157,186		$	5,427	$	5,069	$	358
15	OTHER PRODUCTION: [1]									
16	OTHER (CT's)	$	3,589,249	4.46%	$	160,171	$	140,862	$	19,310
17	OTHER (CT's Land)		10,002	2.65%		265		127		138
18	OTHER (SOLAR)		192,184	5.15%		9,901		9,895		6
19	NC IMPAIRMENT - OTHER		(639)	4.46%		(29)		(22)		(6)
20	WHS IMPAIRMENT - OTHER		(300)	4.46%		(13)		(1)		(12)
21		$	3,790,496		$	170,296	$	150,861	$	19,435
22										
23	TRANSMISSION: [1]									
24	TRANSMISSION OTHER	$	2,814,681	1.90%	$	53,479	$	50,540	$	2,938
25	TRANSMISSION RIGHT OF WAY		191,352	1.15%		2,201		2,120		80
26	OATT CONTRA - TRANS		(4,946)	1.90%		(94)		(89)		(5)
27		$	3,001,087		$	55,586	$	52,572	$	3,014
28										
29	DISTRIBUTION: [1]									
30	DISTRIBUTION OTHER	$	7,541,075	2.50%	$	188,527	$	180,935	$	7,592
31	DISTRIBUTION RIGHT OF WAY		78,566	1.28%		1,006		419		586
32	OATT CONTRA - DISTR		(122)	2.50%		(3)		(3)		(0)
33		$	7,619,518		$	189,529	$	181,352	$	8,178
34										
35	GENERAL: [1]									
36	LAND AND LAND RIGHTS	$	7,866	0.00%	$	-	$	27	$	(27)
37	STRUCTURES AND IMPROVEMENTS		171,677	2.42%		4,155		3,684		471
38	FURNITURE AND EQPMT		25,917	5.00%		1,296		781		515
39	EDP EQUIPMENT		77,981	12.50%		-		8,384		(8,384)
40	TRANSPORTATION EQUIPMENT [2]		63,213	10.29%		-		-		-
41	STORES EQUIPMENT		1,874	5.00%		94		98		(5)
42	TOOLS, SHOPS & GARAGE EQPMT		93,678	5.00%		4,684		4,573		110
43	LABORATORY EQUIPMENT		5,925	6.67%		395		422		(27)
44	POWER OPERATED EQUIPMENT		7,447	5.99%		446		375		71
45	COMMUNICATION EQUIPMENT		236,426	5.00%		11,821		10,026		1,795
46	OATT CONTRA - COMM EQUIP		(134)	5.00%		(7)		(7)		0
47	MISCELLANEOUS EQUIPMENT		20,854	5.00%		1,043		1,306		(263)
48		$	712,725		$	23,927	$	29,670	$	(5,743)
49										
50	INTANGIBLE [4]	$	633,035		$	55,553	$	55,553	$	-
51										
52	TOTAL PLANT-IN-SERVICE	$	30,015,884		$	929,797	$	897,282	$	32,514
53										
54	Electric Plant in Service recovered in riders included above:									
55	JAAR - Steam plant [11]	$	141,779		$	5,435	$	5,451	$	(16)
56	JAAR - Nuclear plant [11]		860,694			30,074		29,455		620
57	DSDR - Transmission [12]		607			12		12		-
58	DSDR - Distribution [12]		196,172			4,982		4,928		54
59	DSDR - General plant [12]		23,853			1,188		1,063		125
60	DSDR - Intangibles [12]		32,842			42		260		(218)
61	Total EPIS recovered in riders (Sum L55 through L60)	$	1,255,948		$	41,732	$	41,168	$	564

[1] The amounts above are shown at Gross Plant in Service Costs. Contra AFUDC has been added back to PowerPlant dollars through the on top in account 101000 at C and the Contra AFUDC depreciation expense that is calculated in 403002 is offset by including Contra AFUDC Offset depreciation groups at E.

[2] Depreciation expense on Vehicles and Construction Equipment are recorded to 803 accounts, rather than 403/404 accounts. Therefore the depreciation expense associated with these assets is excluded from the schedule above.

[3] Totals may not foot due to rounding

[4] Some assets within Misc Intangible Plt are fully amortized and no longer accrue any expense

[5] Land, Land Rights and Rights of Way noted separately from the rest of Electric Plant in Service above. Land is not a depreciable asset while Land Rights and R/W are depreciable.

[6] The calculated accrual column above assumes 12 months of depreciation. If any assets were added during the 12 month period, depreciation would be calculated based on the in-service date in the actual 12me depr booked column above.

[7] The per book intangible amount reflects a representative level of amortization expense on a go forward basis.

[8] Actual amounts provided by Duke Energy Progress - Asset Accounting

[9] NC-0802 - Adjustment to Annualize Depreciation Expense at December 31, 2018

[10] NC-1010 - Twelve Months of Depreciation Expense as of February 29, 2020

[11] Actual balances, calculated accrual and forecasted 12 months ended depreciation expense provided by Rates and Regulatory - Joint Agency Asset Rider support

[12] Actual balances, calculated accrual and forecasted 12 months ended depreciation expense provided by Asset Accounting - DSDR rider support

Smith Rebuttal Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1008
Rebuttal

Plant in Service Balances

Line No.	Description	ACTUALS [1][4] Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Asheville CC [5][6]	Net Change
		a	b	c	d	e	f	g	h	i	j	k	l	m	n	o		p = o - a
1	Electric Plant in Service:																	
2	Steam plant	$ 4,011,861	$ 4,043,991	$ 4,046,676	$ 4,101,612	$ 4,231,983	$ 4,266,772	$ 4,275,052	$ 4,292,783	$ 4,306,563	$ 4,313,743	$ 4,309,252	$ 4,312,479	$ 4,309,657	$ 3,848,827	$ 3,837,973	$ -	$ (173,888)
3	Nuclear plant	8,909,317	8,916,989	8,917,204	8,939,103	9,029,753	9,056,127	9,081,959	9,093,484	9,098,689	9,109,080	9,108,234	9,183,798	9,298,320	9,331,546	9,318,517	-	409,201
4	Hydro plant	143,939	143,757	145,271	145,487	146,482	146,454	146,485	146,479	151,468	152,038	152,192	152,140	153,412	153,538	157,186	-	13,247
5	Other production plant	3,136,771	3,088,719	3,118,877	3,138,170	3,138,093	3,142,793	3,147,464	3,149,023	3,155,174	3,157,109	3,158,903	3,175,483	3,667,888	3,773,704	3,790,495	202,654	856,377
6	Transmission plant	2,746,389	2,751,560	2,756,170	2,761,879	2,792,924	2,816,747	2,838,200	2,847,713	2,859,952	2,867,784	2,916,758	2,945,333	2,972,314	2,982,323	3,010,496	-	264,107
7	Distribution plant	6,944,764	6,980,196	7,025,165	7,065,340	7,113,068	7,180,132	7,239,028	7,289,075	7,343,981	7,385,517	7,441,019	7,483,903	7,497,343	7,543,797	7,607,154	-	662,390
8	General plant	628,616	633,557	639,855	637,103	639,433	646,714	647,285	653,753	650,568	651,968	658,169	660,967	679,878	706,522	712,727	-	84,110
9	Intangible plant	527,370	528,454	529,312	535,638	536,005	538,985	567,009	573,426	573,382	573,593	578,029	581,148	628,365	631,625	633,035	-	105,665
10	Total Electric Plant in Service (Sum L2 through L9)	$ 27,049,028	$ 27,087,223	$ 27,178,530	$ 27,324,333	$ 27,627,742	$ 27,794,724	$ 27,942,482	$ 28,045,736	$ 28,139,777	$ 28,210,833	$ 28,322,555	$ 28,495,252	$ 29,207,178	$ 28,971,882	$ 29,067,584	$ 202,654	$ 2,221,210
11																		
12	Direct Assignments in COS Included above:																	
13	Contra AFUDC - WHS	$ (43,604)	$ (43,604)	$ (43,597)	$ (43,591)	$ (43,591)	$ (43,591)	$ (43,494)	$ (43,476)	$ (43,461)	$ (43,417)	$ (43,283)	$ (43,283)	$ (43,252)	$ (43,190)	$ (43,184)	$ -	$ 421
14	Contra AFUDC - NC Retail	(321,021)	(321,021)	(320,951)	(320,883)	(320,883)	(320,872)	(320,384)	(320,218)	(320,131)	(319,769)	(318,680)	(318,680)	(318,454)	(318,003)	(317,952)	-	3,069
15	Contra AFUDC - SC Retail	(36,217)	(36,217)	(36,212)	(36,206)	(36,206)	(36,206)	(36,150)	(36,133)	(36,128)	(36,085)	(35,955)	(35,955)	(35,927)	(35,872)	(35,865)	-	352
16	Harris Disallowance - NC	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	(387,936)	-	-
17	Harris Disallowance - SC	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	(52,557)	-	-
18	Harris Disallowance - WHS	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	(86,025)	-	-
19	Harris Disallowance - PA	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	(24,780)	-	-
20	Production Plant - Other NC	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	(11,032)	-	-
21	Production Plant - WHS	-	-	-	-	-	-	-	-	-	-	-	-	(4,966)	(4,966)	(4,966)	-	(4,966)
22	OATT - WHS	(5,204)	(5,204)	(5,200)	(5,200)	(5,196)	(5,196)	(5,196)	(5,200)	(5,200)	(5,200)	(5,200)	(5,201)	(5,201)	(5,201)	(5,201)	-	2
23	Total Direct Assignments in COS (Sum L13 through L22)	$ (968,376)	$ (968,376)	$ (968,289)	$ (968,209)	$ (968,205)	$ (968,195)	$ (967,553)	$ (967,358)	$ (967,250)	$ (966,801)	$ (965,448)	$ (965,449)	$ (970,129)	$ (969,563)	$ (969,498)	$ -	$ (1,122)
24																		
25	COS Adjustments																	
26	Acquisition Adjustment	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ -	$ -
27	Total COS Adjustments (Sum L26)	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ 349,802	$ -	$ -
28																		
29	COS Electric Plant in Service:																	
30	Production Plant ((Sum L2 through L5 + L27) - Sum L13 through L21	$ 17,514,863	$ 17,506,431	$ 17,540,919	$ 17,637,184	$ 17,859,123	$ 17,924,947	$ 17,963,119	$ 17,993,729	$ 18,023,745	$ 18,043,373	$ 18,038,630	$ 18,133,950	$ 18,744,008	$ 18,421,778	$ 18,418,270	$ 202,654	$ 1,106,061
31	Direct Assignments - NC (L14 + L16 + L20)	(719,990)	(719,990)	(719,919)	(719,852)	(719,851)	(719,841)	(719,352)	(719,187)	(719,099)	(718,738)	(717,649)	(717,649)	(717,423)	(716,972)	(716,921)	-	3,069
32	Direct Assignments - SC (L15 + L17)	(88,774)	(88,774)	(88,768)	(88,763)	(88,763)	(88,763)	(88,706)	(88,690)	(88,685)	(88,642)	(88,512)	(88,512)	(88,483)	(88,429)	(88,422)	-	352
33	Direct Assignments - WHS (L13 + L18 + L19 + L21 + L22)	(159,612)	(159,612)	(159,601)	(159,595)	(159,591)	(159,591)	(159,494)	(159,481)	(159,466)	(159,422)	(159,287)	(159,288)	(164,223)	(164,162)	(164,155)	-	(4,543)
34	Transmission plant (L6 - L22)	2,751,593	2,756,763	2,761,370	2,767,079	2,798,120	2,821,943	2,843,396	2,852,913	2,865,152	2,872,984	2,921,958	2,950,534	2,977,515	2,987,524	3,015,698	-	264,105
35	Distribution plant (L7)	6,944,764	6,980,196	7,025,165	7,065,340	7,113,068	7,180,132	7,239,028	7,289,075	7,343,981	7,385,517	7,441,019	7,483,903	7,497,343	7,543,797	7,607,154	-	662,390
36	General plant (L8)	628,616	633,557	639,855	637,103	639,433	646,714	647,285	653,753	650,568	651,968	658,169	660,967	679,878	706,522	712,727	-	84,110
37	Intangible plant (L9)	527,370	528,454	529,312	535,638	536,005	538,985	567,009	573,426	573,382	573,593	578,029	581,148	628,365	631,625	633,035	-	105,665
38	Total COS Electric Plant in Service (Sum L30 through L37)	$ 27,398,830	$ 27,437,025	$ 27,528,332	$ 27,674,135	$ 27,977,544	$ 28,144,526	$ 28,292,284	$ 28,395,538	$ 28,489,579	$ 28,560,635	$ 28,672,357	$ 28,845,054	$ 29,556,980	$ 29,321,684	$ 29,417,386	$ 202,654	$ 2,221,210
39																		
40	Solar Electric Plant in Service Included in Line 5 above:	$ 192,221	$ 192,221	$ 192,221	$ 191,936	$ 192,022	$ 192,031	$ 192,031	$ 192,039	$ 192,221	$ 192,039	$ 192,082	$ 192,088	$ 192,088	$ 192,088	$ 192,174	$ -	$ (47)
41																		
42	Electric Plant in Service recovered in riders included above:																	
43	JAAR - Steam plant [2]	$ 119,018														$ 141,779	$ -	$ 22,762
44	JAAR - Nuclear plant [2]	785,214														860,694	-	75,480
45	JAAR - Acquisition Adjustment [2]	349,802														349,802	-	0
46	DSDR - Transmission [3]	607														607	-	-
47	DSDR - Distribution [3]	165,251														196,172	-	30,921
48	DSDR - General plant [3]	17,154														23,853	-	6,699
49	DSDR - Intangibles [3]	32,842														32,842	-	-
50	Total EPIS recovered in riders (Sum L43 through L49)	$ 1,469,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,605,751	$ -	$ 135,862

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Actual balances provided by Rates and Regulatory - Joint Agency Asset Rider support
[3] Actual balances provided by Asset Accounting for the Distribution System Demand Response rider support
[4] Amounts above do not include Asset Retirement Obligation (ARO) or Capital Lease balances
[5] Amounts represent Asheville CC's plant in service that was placed in service on April 5, 2020. See NC-3405.
[6] The Company adjusted the Asheville CC project costs to exclude Task Force consulting expenses noted in PS DR 125-5 from rate base.

I/A

Smith Rebuttal Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1009
Rebuttal

Accumulated Depreciation Balances

Line No.	Description	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Net Change
		ACTUALS [1][4]															
		a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p = o - a
1	Accumulated Depreciation																
2	Steam plant	$ (2,011,905)	$ (2,019,818)	$ (2,030,802)	$ (2,045,887)	$ (2,044,204)	$ (2,059,607)	$ (2,080,807)	$ (2,105,933)	$ (2,124,886)	$ (2,142,407)	$ (2,145,509)	$ (2,154,317)	$ (2,161,285)	$ (1,835,584)	$ (1,862,933)	$ 148,972
3	Nuclear plant	(4,430,694)	(4,445,828)	(4,465,220)	(4,485,722)	(4,490,599)	(4,503,309)	(4,504,855)	(4,520,143)	(4,536,943)	(4,547,715)	(4,566,923)	(4,543,646)	(4,538,036)	(4,548,229)	(4,541,755)	(111,061)
4	Hydro plant	(46,007)	(46,412)	(48,279)	(48,734)	(48,654)	(48,747)	(49,138)	(49,480)	(49,287)	(49,302)	(49,644)	(49,397)	(48,697)	(49,055)	(47,202)	(1,195)
5	Other production plant	(671,003)	(633,115)	(674,481)	(705,483)	(714,393)	(729,565)	(741,728)	(753,183)	(730,673)	(752,679)	(763,208)	(771,014)	(781,562)	(794,155)	(796,214)	(125,211)
6	Transmission plant	(816,198)	(815,911)	(821,258)	(823,868)	(824,684)	(827,644)	(832,098)	(834,554)	(838,498)	(843,308)	(842,303)	(845,584)	(842,971)	(844,425)	(848,981)	(32,784)
7	Distribution plant	(3,235,148)	(3,227,261)	(3,226,020)	(3,228,109)	(3,228,331)	(3,228,703)	(3,238,531)	(3,240,789)	(3,251,413)	(3,249,457)	(3,253,411)	(3,258,335)	(3,224,680)	(3,228,935)	(3,249,907)	(14,758)
8	General plant	(167,536)	(169,790)	(171,749)	(170,037)	(173,564)	(177,262)	(174,792)	(179,685)	(175,082)	(173,141)	(178,333)	(181,403)	(184,244)	(187,900)	(188,350)	(20,814)
9	Intangible plant	(322,831)	(326,848)	(330,893)	(334,936)	(339,071)	(346,072)	(350,270)	(355,022)	(359,708)	(364,443)	(369,180)	(373,718)	(378,291)	(383,823)	(389,205)	(66,374)
10	Total Accumulated Depreciation (Sum L2 through L9)	$ (11,701,322)	$ (11,684,983)	$ (11,768,701)	$ (11,842,776)	$ (11,863,499)	$ (11,920,910)	$ (11,972,218)	$ (12,038,788)	$ (12,066,492)	$ (12,122,451)	$ (12,168,512)	$ (12,177,415)	$ (12,159,767)	$ (11,872,107)	$ (11,924,547)	$ (223,224)
11																	
12	Direct Assignments in COS Included above:																
13	Rate Difference - SC Retail	$ 24,176	$ 24,069	$ 23,962	$ 23,855	$ 23,748	$ 23,642	$ 23,535	$ 23,428	$ 23,321	$ 23,214	$ 23,107	$ 23,000	$ 22,893	$ 22,786	$ 22,679	$ (1,497)
14	Rate Difference - WHS	7,916	7,881	7,846	7,811	7,776	7,741	7,706	7,671	7,636	7,602	7,567	7,532	7,497	7,462	7,428	(488)
15	Rate Difference - NCEMPA	2,918	2,902	2,886	2,870	2,854	2,838	2,822	2,806	2,791	2,775	2,759	2,743	2,727	2,711	2,695	(223)
16	Contra AFUDC - NC Retail	238,121	238,666	239,130	239,569	240,074	240,567	240,581	240,918	241,332	242,332	241,744	242,076	242,378	242,430	245,095	6,974
17	Contra AFUDC - SC Retail	23,951	24,010	24,064	24,117	24,177	24,236	29,903	29,917	29,971	30,074	30,003	30,039	30,070	24,411	24,723	773
18	Contra AFUDC - WHS	30,312	30,379	30,438	30,496	30,560	30,624	30,642	30,696	30,753	30,913	30,850	30,904	30,946	30,949	31,300	988
19	Harris Disallowance - NC	254,434	254,851	255,268	255,685	256,102	256,519	256,936	257,353	257,770	258,187	258,604	259,021	259,438	259,855	260,272	5,838
20	Harris Disallowance - SC	32,462	32,518	32,575	32,631	32,688	32,744	32,801	32,857	32,914	32,970	33,027	33,083	33,140	33,196	33,253	791
21	Harris Disallowance - WHS	50,127	50,219	50,312	50,404	50,497	50,589	50,682	50,774	50,867	50,959	51,052	51,144	51,237	51,329	51,421	1,295
22	Harris Disallowance - PA	15,761	15,787	15,814	15,841	15,867	15,894	15,921	15,947	15,974	16,001	16,027	16,054	16,080	16,107	16,134	373
23	Production Plant - Other NC	(340,105)	(339,046)	(337,988)	(336,929)	(335,871)	(334,812)	(333,754)	(332,695)	(331,636)	(330,578)	(329,519)	(328,461)	(327,402)	(326,344)	(325,285)	14,820
24	Production Plant - Other SC	(63,159)	(62,970)	(62,781)	(62,592)	(62,403)	(62,214)	(62,025)	(61,836)	(61,647)	(61,458)	(61,268)	(61,079)	(60,890)	(60,701)	(60,512)	2,647
25	Production Plant - WHS	-	-	-	-	-	-	-	-	-	-	-	-	(434)	(434)	(434)	(434)
26	OATT - WHS	1,423	1,431	1,439	1,447	1,455	1,463	1,471	1,480	1,488	1,496	1,504	1,513	1,521	1,529	1,537	114
27	Total Direct Assignments in COS (Sum L13 through L26)	$ 278,335	$ 280,697	$ 282,964	$ 285,205	$ 287,524	$ 289,831	$ 297,222	$ 299,317	$ 301,533	$ 304,486	$ 305,455	$ 307,568	$ 309,199	$ 305,286	$ 310,306	$ 31,971
28																	
29	COS Adjustments																
30	Acquisition Adjustment	$ (43,592)	$ (44,656)	$ (45,719)	$ (46,782)	$ (47,845)	$ (48,908)	$ (49,972)	$ (51,035)	$ (52,098)	$ (53,161)	$ (54,225)	$ (55,288)	$ (56,351)	$ (57,414)	$ (58,478)	$ (14,885)
31	Remove Nuclear Decommissioning ARO in 108000	96,122	96,122	96,122	96,122	96,644	96,644	97,162	97,162	97,162	97,683	97,683	97,683	98,203	98,203	98,203	2,081
32	Total COS Adjustments (Sum L30 through L31)	$ 52,530	$ 51,467	$ 50,403	$ 49,340	$ 48,799	$ 47,736	$ 47,191	$ 46,128	$ 45,064	$ 44,521	$ 43,458	$ 42,395	$ 41,852	$ 40,788	$ 39,725	$ (12,805)
33																	
34	COS Accumulated Depreciation:																
35	Production Plant ((Sum L2 through L5 + L32) - Sum L13 through L25	$ (7,383,992)	$ (7,372,974)	$ (7,449,903)	$ (7,520,244)	$ (7,535,118)	$ (7,581,861)	$ (7,625,087)	$ (7,680,448)	$ (7,696,770)	$ (7,750,571)	$ (7,785,777)	$ (7,782,035)	$ (7,795,406)	$ (7,489,991)	$ (7,517,148)	$ (133,156)
36	Direct Assignments - NC (L16 + L19 + L23)	152,450	154,471	156,410	158,324	160,305	162,273	163,764	165,576	167,465	169,941	170,829	172,636	174,414	175,941	180,082	27,632
37	Direct Assignments - SC (L13 + L17 + L20 + L24)	17,429	17,627	17,819	18,012	18,210	18,408	24,213	24,366	24,559	24,800	24,868	25,043	25,212	19,692	20,143	2,714
38	Direct Assignments - WHS (L14 + L15 + L18 + L21 + L22 + L25 + L2	108,456	108,600	108,735	108,870	109,009	109,150	109,245	109,375	109,509	109,745	109,758	109,889	109,573	109,653	110,081	1,625
39	Transmission plant (L6 - L26)	(817,620)	(817,342)	(822,697)	(825,315)	(826,139)	(829,107)	(833,569)	(836,033)	(839,986)	(844,804)	(843,808)	(847,097)	(844,492)	(845,954)	(850,518)	(32,898)
40	Distribution plant (L7)	(3,235,148)	(3,227,261)	(3,226,020)	(3,228,109)	(3,228,331)	(3,228,703)	(3,238,531)	(3,240,789)	(3,251,413)	(3,249,457)	(3,253,411)	(3,258,335)	(3,224,680)	(3,228,935)	(3,249,907)	(14,758)
41	General plant (L8)	(167,536)	(169,790)	(171,749)	(170,037)	(173,564)	(177,262)	(174,792)	(179,685)	(175,082)	(173,141)	(178,333)	(181,403)	(184,244)	(187,900)	(188,350)	(20,814)
42	Intangible plant (L9)	(322,831)	(326,848)	(330,893)	(334,936)	(339,071)	(346,072)	(350,270)	(355,022)	(359,708)	(364,443)	(369,180)	(373,718)	(378,291)	(383,823)	(389,205)	(66,374)
43	Total COS Accumulated Depreciation (Sum L35 through L42)	$ (11,648,793)	$ (11,633,517)	$ (11,718,298)	$ (11,793,436)	$ (11,814,700)	$ (11,873,174)	$ (11,925,027)	$ (11,992,660)	$ (12,021,428)	$ (12,077,930)	$ (12,125,054)	$ (12,135,020)	$ (12,117,915)	$ (11,831,318)	$ (11,884,821)	$ (236,029)
44																	
45	Accumulated Depreciation recovered in riders included above:																
46	JAAR - Steam plant [2]	$ (19,888)														$ (26,236)	$ (6,349)
47	JAAR - Nuclear plant [2]	(90,234)														(124,077)	(33,843)
48	JAAR - Acquisition Adjustment [2]	(43,592)														(58,477)	(14,885)
49	DSDR - Transmission [3]	(101)														(114)	(13)
50	DSDR - Distribution [3]	(44,120)														(50,328)	(6,208)
51	DSDR - General plant [3]	(4,890)														(6,182)	(1,292)
52	DSDR - Intangibles [3]	(32,431)														(32,818)	(387)
53	Total Accum Depr recovered in riders (Sum L46 through L52)	$ (235,256)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (298,233)	$ (62,977)

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Actual balances provided by Rates and Regulatory - Joint Agency Asset Rider support
[3] Actual balances provided by Asset Accounting for the Distribution System Demand Response rider support
[4] Amounts above do not include Asset Retirement Obligation (ARO) reserve balances in accounts 0108155,0108315,0108499, or 0108640

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1010
Rebuttal

Twelve Months of Depreciation Expense as of Feb. 29, 2020

Line No.	Description	ACTUALS [1][2][3] Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	12 MONTHS
		a	b	c	d	e	f	g	h	i	j	k	l	m = sum(a:l)
1	Function													
2	STEAM PLANT	$ 12,606	$ 12,709	$ 12,991	$ 13,047	$ 12,899	$ 12,979	$ 12,920	$ 13,027	$ 13,021	$ 13,120	$ 13,113	$ 11,737	$ 154,170
3	LAND RIGHTS - STEAM	3	3	3	3	3	3	3	3	3	3	3	3	30
4	NC IMPAIRMENT - STEAM	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(415)
5	WHS IMPAIRMENT - STEAM	-	-	-	-	-	-	-	-	-	-	-	-	-
6	NUCLEAR PLANT	21,842	21,897	22,143	22,204	22,265	22,287	21,695	22,338	22,325	22,486	23,405	22,856	267,743
7	LAND RIGHTS - NUCLEAR	56	56	56	56	56	56	56	56	56	56	56	56	677
8	HYDRAULIC PLANT	412	413	415	415	415	415	407	430	430	424	455	434	5,066
9	LAND RIGHTS - HYDRO	0	0	0	0	0	0	0	0	0	0	0	0	4
10	OTHER (CT's)	11,249	11,337	11,207	11,218	11,206	11,209	11,352	11,404	11,458	12,960	12,897	13,365	140,862
11	OTHER (CT's Land)	11	11	11	11	11	11	11	11	11	11	11	11	127
12	OTHER (SOLAR)	825	824	824	824	824	824	824	825	825	825	825	825	9,895
13	NC IMPAIRMENT - OTHER	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(22)
14	WHS IMPAIRMENT - OTHER	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
15	TRANSMISSION OTHER	4,040	4,046	4,094	4,149	4,180	4,195	4,162	4,225	4,295	4,323	4,435	4,398	50,540
16	TRANSMISSION RIGHT OF WAY	177	177	177	177	177	177	177	177	177	177	177	177	2,120
17	OATT CONTRA - TRANS	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(89)
18	DISTRIBUTION OTHER	15,293	14,385	14,511	15,247	14,833	14,958	14,796	15,133	15,231	15,277	15,751	15,520	180,935
19	DISTRIBUTION RIGHT OF WAY	34	35	35	35	35	35	35	35	35	35	35	35	419
20	OATT CONTRA - DISTR	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
21	GENERAL LAND AND LAND RIGHTS	2	2	2	2	2	2	2	2	2	2	2	2	27
22	GENERAL STRUCTURES AND IMPROVEMENTS	319	314	312	321	319	318	323	323	322	149	321	343	3,684
23	GENERAL FURNITURE AND EQPMT	68	68	69	69	70	70	70	69	69	17	68	74	781
24	GENERAL EDP EQUIPMENT	665	667	674	691	690	697	689	690	690	682	772	777	8,384
25	GENERAL TRANSPORTATION EQUIPMENT [4]	-	-	-	-	-	-	-	-	-	-	-	-	-
26	GENERAL STORES EQUIPMENT	9	9	9	9	9	8	8	8	8	8	8	8	98
27	GENERAL TOOLS, SHOPS & GARAGE EQPMT	377	377	379	380	381	383	377	378	379	382	390	390	4,573
28	GENERAL LABORATORY EQUIPMENT	37	37	37	37	37	37	33	33	33	33	33	33	422
29	GENERAL POWER OPERATED EQUIPMENT	28	28	28	28	30	30	30	30	30	37	37	37	375
30	GENERAL COMMUNICATION EQUIPMENT	774	781	788	791	794	809	827	850	872	847	920	973	10,026
31	OATT CONTRA - COMM EQUIP	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(7)
32	GENERAL MISCELLANEOUS EQUIPMENT	100	103	103	103	103	103	(99)	83	84	266	267	90	1,306
33	INTANGIBLE	4,043	4,135	4,121	4,197	4,752	4,789	4,735	4,737	4,538	4,574	5,532	5,400	55,553
34	Total Depreciation (Sum L2 through L33)	$ 72,924	$ 72,370	$ 72,945	$ 73,971	$ 74,049	$ 74,352	$ 73,388	$ 74,820	$ 74,847	$ 76,649	$ 79,467	$ 77,500	$ 897,282

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting
[2] Amounts above do not include Asset Retirement Obligation (ARO) balances
[3] Depreciation expense on vehicles is recorded to 803 accounts, therefore it is excluded above.

Duke Energy Progress, LLC NC-1011
Docket No. E-2, Sub 1219 Rebuttal
Adjust for post test year additions to plant in service
For the test period ended December 31, 2018
(Dollars in thousands)

Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142

Line No.	Description	Total System		NC Retail Allocation	Total NC Retail
1	Summary of impacts to rate base				
2	Asheville CWIP Balance as of 10/30/2017	$ 169,850	[1]	60.6008% [1]	$ 102,930
3					
4	Remove Asheville CWIP in Rate Base (-L2)	$ (169,850)			$ (102,930)

[1] Docket No. E-2, Sub 1142 - NC-1200(F) - Update Adjust for Asheville base load CWIP - Oct Update

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1200
Rebuttal

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma annualizes test period operation and maintenance expenses excluding fuel, purchased power, and labor and benefit costs to reflect the change in unit costs that occurred during the test period.

The impact to operation and maintenance expenses is determined as follows:

First, calculate total operation and maintenance expense excluding fuel and purchased power but including labor that needs to be adjusted. This calculation is done by starting with per book operation and maintenance expense, excluding fuel and purchased power, and subtracting all pro-forma adjustments that impacted this amount.

Second, subtract net electric operation and maintenance salaries and wages from operation and maintenance expenses including labor.

Third, subtract fringe benefits from operation and maintenance expenses including labor. Fringe benefits are calculated by multiplying net electric operation and maintenance salaries and wages by the fringe benefits contribution rate.

Finally, the impact to operation and maintenance expense is calculated by multiplying total non-labor operation and maintenance expenses by the average inflation rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update

Updated NC-1201 to remove CertainTeed cost adjustment in accordance with Commission order under Docket No. E-2, Sub 1204

November update

Updated NC-1203, NC-1204 and NC-1205 for most up to date index values

December update

Updated index values on NC-1203, NC-1204 and NC-1205 and for impacts flowing from other adjustments

January update

Updated index values on NC-1203, NC-1204 and NC-1205 and for impacts flowing from other adjustments

February update

Updated for impacts flowing from other adjustments; No revision made to index values as updates were not available as of Supplemental filing date

Rebuttal

Updated NC-1203, NC-1204 and NC-1205 for index values through February 2020.
Updated average inflation rate on NC-1201

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1200
Rebuttal

Line No.	Description	Source	Total NC Retail Rebuttal	Total NC Retail Application	Total NC Retail Change
1			Rebuttal	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-1201	4,241	1,311	2,930
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1201	(983)	(304)	(679)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L6 through L15	3,259	1,007	2,251
18					
19	Operating income	L4 - L17	$ (3,259)	$ (1,007)	$ (2,251)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC NC-1201
Docket No. E-2, Sub 1219 Rebuttal
Annualize O&M non-labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Rebuttal Total System		NC Retail Allocation		Rebuttal Total NC Retail	
1							
2							
3	O&M (excluding fuel and purchased power)	$ 1,546,719	[1]			$ 1,050,819	[1]
4							
5	Less: reagents expense and proceeds from sale of by-products	(102,730)	[2]			(62,778)	[2]
6	Less: costs recovered through non-fuel riders	(192,911)	[3]			(136,143)	[3]
7	Less: Ernst & Young outside tax services contract	(592)	[4]	66.2120%	[20]	(392)	[4]
8	Less: nuclear refueling outage costs	(40,225)	[5]			(40,225)	[5]
9	Less: amortization of prior rate case costs	(1,012)	[6]			(1,012)	[6]
10	Less: aviation expenses	(1,579)	[7]	66.2120%	[20]	(1,045)	[7]
11	Less: expiring amortizations	(1,673)	[8]			(1,673)	[8]
12	Less: merger related costs	(5,969)	[9]			(4,039)	[9]
13	Less: severance and retention costs	(52,890)	[10]	66.2120%	[20]	(35,020)	[10]
14	Less: vegetation management expenses - distribution	(36,515)	[11]	83.9171%	[18]	(30,643)	[11]
15	Less: vegetation management expenses - transmission	(8,143)	[11]	59.6699%	[19]	(4,859)	[11]
16	Less: NCUC regulatory fee	(4,889)	[12]			(4,889)	[12]
17	Less: CertainTeed payment obligation	-	[13]	61.1093%	[21]	-	[13]
18							
19							
20	Total O&M to be adjusted including labor (Sum L3 through L18)	$ 1,097,593				$ 728,104	
21							
22	Net electric O&M salaries and wages	$ 649,874	[14]				
23	Fringe benefits contribution rate	20.50%	[15]				
24	Fringe benefits (L22 x L23)	$ 133,210					
25							
26	Less: net electric O&M salaries & wages and fringe benefits (L22 + L24)	$ 783,084		66.2120%	[20]	$ 518,496	
27							
28	Total non-labor O&M to be adjusted (L20 - L26)	$ 314,509				$ 209,608	
29	Average inflation rate	2.02%	[16]			2.02%	[15]
30	Impact to O&M - non-labor O&M adjustment to reflect end of period costs (L28 x L29)	$ 6,364				$ 4,241	
31							
32	Statutory tax rate	23.1693%	[17]			23.1693%	[16]
33	Impact to income taxes (-L30 x L32)	$ (1,474)				$ (983)	
34	Impact to operating income (-L30 - L33)	$ (4,889)				$ (3,259)	

[1] Smith Exhibit 1, Other O&M, Page 1, Line 4, Columns 1 and 2
[2] NC-0201 - Update fuel costs to approved rate
[3] NC-0601 - Eliminate costs recovered through non-fuel riders, Line 23
[4] NC-1311 - Adjustment to annualized Ernst & Young outside tax services contract, Line 2
[5] NC-1501 - Levelize nuclear refueling outage costs, Line 21
[6] E-1 Item 45A
[7] NC-1702 - Adjust aviation expenses, Line 5
[8] NC-1801 - Adjust for approved regulatory assets and liabilities, Line 3
[9] NC-1901 - Adjust for merger related costs, Line 4
[10] NC-2001 - Amortize severance costs - Actuals, Line 4
[11] NC-2702 - Adjust for vegetation management - distribution and transmission, Lines 11 and 23
[12] E-1 Item 45A
[13] NC-3301, Line 10
[14] NC-1301, Line 14
[15] NC-1301, Line 34
[16] NC-1203 - Average of Consumer Price Index and Producer Price Index, Line 19
[17] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[18] NC Retail Allocation Factor - RB_PLT_O_DI_OH_LN
[19] NC Retail Allocation Factor - DTALL
[20] NC Retail Allocation Factor - LAB
[21] NC Retail Allocation Factor - E1ALL
[22] NC-2503 - Annualized credit/debit card and ACH transactions - NC Residential Only - Line 24

Duke Energy Progress, LLC NC-1202
Docket No. E-2, Sub 1219 Rebuttal
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

Average of Consumer Price Index and Producer Price Index

Line No.	Period	CPI [1] (a)	PPI [2] Finished goods less food & energy (b)	PPI [3] Processed materials less food & energy (c)	PPI Average (d)= Average of (b) and (c)
1	December 2017	246.5	200.6	196.3	
2	January 2018	247.9	200.9	197.2	
3	February 2018	249.0	201.3	198.3	
4	March 2018	249.6	201.8	199.3	
5	April 2018	250.5	202.3	199.8	
6	May 2018	251.6	202.7	201.3	
7	June 2018	252.0	203.1	202.3	
8	July 2018	252.0	203.7	203.0	
9	August 2018	252.1	204.2	203.7	
10	September 2018	252.4	204.6	204.5	
11	October 2018	252.9	205.1	204.8	
12	November 2018	252.0	205.6	204.2	
13	December 2018	251.2	205.8	203.1	
14					
15	February 2020	258.7	209.1	199.2	
16					
17	13 month average	250.8	203.2	201.4	
18					
19	Increase from average to year end (L15 - L17)	7.9	5.9	(2.2)	
20	% increase from average to year end (L19 / L17)	3.14%	2.90%	-1.09%	0.91%
21	Average inflation rate (Average, Line 18, Col. (a) and Col. (d))	2.02%			

[1] NC-1203 - Consumer Price Index - All Items
[2] NC-1204 - Producer Price Index - Commodities - Finished goods less food and energy
[3] NC-1205 - Producer Price Index - Commodities - Processed materials less food and energy

Note: Totals may not foot due to rounding.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1203
Rebuttal

Consumer Price Index - All Urban Consumers
Original Data Value

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	211.1	212.2	212.7	213.2	213.9	215.7	215.4	215.8	216.0	216.2	216.3	215.9	214.5
2010	216.7	216.7	217.6	218.0	218.2	218.0	218.0	218.3	218.4	218.7	218.8	219.2	218.1
2011	220.2	221.3	223.5	224.9	226.0	225.7	225.9	226.5	226.9	226.4	226.2	225.7	224.9
2012	226.7	227.7	229.4	230.1	229.8	229.5	229.1	230.4	231.4	231.3	230.2	229.6	229.6
2013	230.3	232.2	232.8	232.5	232.9	233.5	233.6	233.9	234.1	233.5	233.1	233.0	233.0
2014	233.9	234.8	236.3	237.1	237.9	238.3	238.3	237.9	238.0	237.4	236.2	234.8	236.7
2015	233.7	234.7	236.1	236.6	237.8	238.6	238.7	238.3	237.9	237.8	237.3	236.5	237.0
2016	236.9	237.1	238.1	239.3	240.2	241.0	240.6	240.8	241.4	241.7	241.4	241.4	240.0
2017	242.8	243.6	243.8	244.5	244.7	245.0	244.8	245.5	246.8	246.7	246.7	246.5	245.1
2018	247.9	249.0	249.6	250.5	251.6	252.0	252.0	252.1	252.4	252.9	252.0	251.2	251.1
2019	251.7	252.8	254.2	255.5	256.1	256.1	256.6	256.6	256.8	257.3	257.2	257.0	255.7
2020	258.0	258.7											258.3

Source: Bureau of Labor Statistics

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1204
Rebuttal

Producer Price Index-Commodities
Original Data Value

Series Id: WPSFD4131
Seasonally Adjusted
Group: Final demand
Item: Finished goods less foods and energy
Base Date: 198200
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	170.8	170.9	171.2	171.3	171.2	171.8	171.4	171.8	171.6	171.5	172.1	172.1	171.5
2010	172.5	172.6	172.9	172.9	173.4	173.6	173.7	173.9	174.3	174.3	174.3	174.6	173.6
2011	175.3	175.7	176.2	176.8	177.0	177.6	178.2	178.5	179.0	179.4	179.6	180.0	177.8
2012	180.7	181.0	181.3	181.6	181.8	182.1	182.9	183.2	183.2	183.3	183.7	183.7	182.4
2013	183.9	184.2	184.4	184.6	184.8	185.0	185.2	185.3	185.4	185.6	185.9	186.7	185.1
2014	187.5	187.7	187.7	187.9	188.2	188.5	188.7	189.0	189.2	189.7	189.7	189.8	188.6
2015	190.7	191.3	191.5	191.6	191.8	192.7	193.0	193.0	193.2	193.0	193.1	193.4	192.4
2016	193.9	194.2	194.3	194.6	194.9	195.4	195.4	195.7	195.8	196.1	196.3	196.7	195.3
2017	197.1	197.4	197.8	198.5	198.6	198.8	198.9	199.2	199.2	200.0	200.5	200.6	198.9
2018	200.9	201.3	201.8	202.3	202.7	203.1	203.7	204.2	204.6	205.1	205.6	205.8	203.4
2019	206.6	206.9	207.2	207.5	207.8	207.7	208.1	208.2	208.4	208.4	208.7	209.0	207.9
2020	209.1	209.1											209.1

Source: Bureau of Labor Statistics

Note: Items highlighted green above are preliminary. All indexes are subject to revision four months after original publication.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1205
Rebuttal

Producer Price Index-Commodities
Original Data Value

Series Id: WPSID69115
Seasonally Adjusted
Group: Intermediate demand by commodity type
Item: Processed materials less foods and
Base Date: 198200
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	174.8	173.5	172.7	171.8	171.4	171.8	172.2	173.2	174.2	174.5	174.9	175.9	173.4
2010	177.0	178.4	179.6	181.4	181.8	180.9	180.2	180.5	180.9	182.0	183.1	184.1	180.8
2011	186.6	188.8	190.2	192.4	193.5	193.7	194.2	194.2	194.2	193.0	192.3	191.3	192.0
2012	192.0	193.2	194.5	194.7	194.1	191.9	191.2	191.3	192.0	192.2	192.1	192.6	192.7
2013	193.7	194.7	194.4	193.9	193.6	193.5	193.3	193.7	193.7	193.6	193.6	194.0	193.8
2014	194.6	195.2	194.8	195.1	195.0	195.1	195.9	196.3	196.3	195.8	194.9	193.9	195.2
2015	191.8	191.1	190.5	190.1	190.1	190.2	190.0	189.1	188.1	187.7	187.1	186.6	189.4
2016	185.8	185.2	185.1	185.7	186.2	186.6	186.9	187.4	187.7	188.0	188.7	189.4	186.9
2017	190.0	191.3	192.1	192.9	192.8	193.1	192.9	193.5	194.2	195.0	196.0	196.3	193.3
2018	197.2	198.3	199.3	199.8	201.3	202.3	203.0	203.7	204.5	204.8	204.2	203.1	201.8
2019	203.1	202.7	202.4	202.2	201.7	201.0	200.7	200.0	199.7	200.2	199.4	199.1	201.0
2020	199.6	199.2											199.4

Source: Bureau of Labor Statistics

Note: Items highlighted green above are preliminary. All indexes are subject to revision four months after original publication.

Duke Energy Progress, LLC NC-2200
Docket No. E-2, Sub 1219 Rebuttal
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro-forma adjusts income taxes to reflect the tax impact that results from annualizing interest expense based on the end-of-period, adjusted rate base.

The impact to income taxes was determined as follows:

First, multiply rate base after all pro-forma adjustments have been made by the long-term debt ratio to calculate an adjusted long-term debt balance. Second, multiply the adjusted long-term debt balance by the end of year cost of long-term debt to calculate annualized interest expense. Third, subtract interest expense incurred during the test period from annualized interest expense and multiply the difference by the statutory tax rate.

Duke Energy Progress, LLC NC-2200
Docket No. E-2, Sub 1219 Rebuttal
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Source	Total NC Retail Rebuttal	February Application		Change
1			Rebuttal	February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue		$ -	$ -	$ -	$ -
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation		-	-	-	-
9	Purchased power		-	-	-	-
10	Other operation and maintenance expense		-	-	-	-
11	Depreciation and amortization		-	-	-	-
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes	NC-2201	1,271	786	123	1,148
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	1,271	786	123	1,148
18						
19	Operating income	L4 - L17	$ (1,271)	$ (786)	$ (123)	$ (1,148)
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					
24						
25						
26	**Pro Formas Impacting Rate Base Line Items**					
27						
28	Electric plant in service		$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-
31						
32	Add:					
33	Materials and supplies		-	-	-	-
34	Working capital investment		-	-	-	-
35						
36						
37	Less:					
38	Accumulated deferred taxes		-	-	-	-
39	Operating reserves		-	-	-	-
40						
41						
42	Construction work in progress		-	-	-	-
43						
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -
45						
46	Note:					
47	Rate Base: positive number increases rate base / negative number decreases rate base					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2201
Rebuttal

Line No.	Description	Total System Col [a]		NC Retail Allocation Col [b]		Total NC Retail Col [c]	
1							
2	Rate base before pro forma adjustments	$ 14,580,739	[1]	67.6169%	[2]	$ 9,859,050	[1]
3							
4	Pro forma rate base before working capital adjustment	$ 15,794,913	[3]			$ 10,680,038	
5							
6	Long-term debt ratio	47.0000%	[4]			47.0000%	[4]
7	Calculated long-term debt (L4 x L6)	$ 7,423,609				$ 5,019,618	
8							
9	End of year cost of long-term debt	4.1074%	[4]			4.1074%	[4]
10	Annualized interest expense (L7 x L9)	$ 304,920				$ 206,177	
11							
12	Incurred interest expense	315,466	[5]	67.0949%	[6]	211,661	
13	Less interest on customer deposits	(8,643)	[7]			(7,971)	[7]
14	Net interest expense	306,823				203,690	
15							
16	Increase / <decrease> to interest costs (L10 - L14)	$ (1,903)				$ (5,484)	
17							
18	Statutory tax rate	23.1693%	[8]			23.1693%	[8]
19	Impact to income taxes (-L16 x L18)	$ 441				$ 1,271	
20							
21	Impact to operating income (-L19)	$ (441)				$ (1,271)	

[1] Smith Exhibit 1, Page 1, Line 12
[2] NC Retail Allocation Factor - Calculation: L2, Col [c] / L2, Col [a]
[3] Calculation: L4, Col [c] / L2, Col [b]
[4] Smith Exhibit 1, Page 2, Line 1
[5] Cost of Service, E-1 Item 45a, Total Other Interest Expense, Line 702
[6] NC Retail Allocation Factor - Net Book Plant
[7] Smith Exhibit 1, Page 1, Line 7
[8] NC-0104 - 2019 Tax Rate, Line 10

Duke Energy Progress, LLC NC-2300
Docket No. E-2, Sub 1219 Rebuttal
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required as a result of the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 order in Docket No. M-100 Sub 137.

October Update
Reflects changes for October updates to actuals

November Update
Reflects changes for November actuals

December Update
Reflects changes for December actuals

January Update
Reflects changes for January 2020 actuals

February Update
Reflects changes for February 2020 actuals and revised E&Y Lead Lag Study

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2300
Rebuttal

Line No.	Description	Source	Rebuttal Present	Rebuttal Proposed	Total NC Retail Application Present	Total NC Retail Application Proposed	Change Present	Change Proposed
1								
2	**Pro Formas Impacting Income Statement Line Items**							
3								
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -
5								
6	Electric operating expenses:							
7	Operation and maintenance							
8	Fuel used in electric generation		-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-
14	Income taxes	NC-2301 & NC-2302	95	(309)	122	(337)	(27)	28
15	Amortization of investment tax credit		-	-	-	-	-	-
16								
17	Total electric operating expenses	Sum L8 through L15	95	(309)	122	(337)	(27)	28
18								
19	Operating income	L4 - L17	$ (95)	$ 309	$ (122)	$ 337	$ 27	$ (28)
20								
21	Notes:							
22	Revenue: positive number increases revenue / negative number decreases revenue							
23	Expense: positive number increases expense / negative number decreases expense							
24								
25								
26	**Pro Formas Impacting Rate Base Line Items**							
27								
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-
31								
32	Add:							
33	Materials and supplies		-	-	-	-	-	-
34	Working capital investment	NC-2302	(21,219)	69,087	(27,013)	74,407	5,794	(5,320)
35								
36								
37	Less:							
38	Accumulated deferred taxes		-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-
40								
41								
42	Construction work in progress		-	-	-	-	-	-
43								
44	Total impact to rate base	Sum L30 through L42	$ (21,219)	$ 69,087	$ (27,013)	$ 74,407	$ 5,794	$ (5,320)
45								
46	Note:							
47	Rate Base: positive number increases rate base / negative number decreases rate base							

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Rebuttal

		NC Retail					
		Financials			Iteration 1		
Line No.	Description	Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Increase (d) = (e) - (a)	With Increase (e) = (a) + (d)	Weighted Lead Lag Days (f)
1	Total Adjusted Present Revenue	$ 3,361,009 [1]					42.09 [1]
2	Revenue Increase (L3)	-	544,261		537,995		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009	544,261	3,905,270	537,995	3,899,004	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	851,653 [1]	-	851,653		851,653	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	862,817 [1]					37.38 [1]
10	Revenue Increase (L11)		2,009		1,986		37.32 [7]
11	Operation and Maintenace Expense with Increase	862,817	2,009	864,826	1,986 [3]	864,803	37.38 [8]
12							
13	Total Adjusted Depreciation and Amortization	960,468 [1]	-	960,468		960,468	0.00 [1]
14	Total Adjusted General Taxes	103,598 [1]	-	103,598		103,598	138.14 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	45,506 [1]					8.05 [1]
18	Revenue Increase (L19)		125,327		124,190		-20.60 [7]
19	Income Taxes with Increase	45,506	125,327	170,833	124,190 [4]	169,695	-12.91 [8]
20							
21	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,985,196	127,336	3,112,532	126,175	3,111,372	24.12 [9]
23							
24	Income for Return (L3 - L22)	375,813	416,925	792,738	411,820	787,633 [5]	22.91 [9]
25	Interest Expense	205,768 [1]	1,334	207,101	-	205,768 [6]	87.70 [1]
26	Return for Equity (L24 - L25)	170,045	415,592	585,636	411,820	581,865	0.00 [1]
27							
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009		$ 3,905,270		$ 3,899,004	23.88 [9]
29							
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,658,819 [1]	$ 69,087	$ 10,727,906		$ 10,658,819	
31							
32	Overall Rate of Return (L24 / L30)	3.53%		7.39%		7.39%	
33	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]	
34							
35			Revenue	Adjusted			
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
37	Annual Requirement (L3 and/or L28)	$ 3,361,009		$ 3,905,270		$ 3,899,004	
38	Daily Requirement (L37 / 365 Days)	$ 9,208		$ 10,699		$ 10,682	
39	Net Lag Days	13.64 [1]		18.19		18.18	
40							
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,582	$ 69,087	$ 194,669	$ 68,629	$ 194,211	
42	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,342	$ 69,087	$ 199,429			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Rebuttal

Line No.	Description	NC Re Financials Adjusted with CWC (a)		Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)		NC Retail Iteration 2 Increase (g) = (h) - (e)		With Increase (h) = (e) + (g)		Weighted Lead Lag Days (i)	
1	Total Adjusted Present Revenue	$ 3,361,009	[1]								42.09	[1]
2	Revenue Increase (L3)	-		544,261			6,224				41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009		544,261	3,905,270		6,224		3,905,228		42.06	[8]
4												
5	Operating Expenses:											
6	Fuel Used in Electric Generation	851,653	[1]	-	851,653				851,653		28.49	[1]
7	Purchased Power	156,798	[1]	-	156,798				156,798		33.44	[1]
8												
9	Operation & Maintenance Expense	862,817	[1]								37.38	[1]
10	Revenue Increase (L11)			2,009			23		23		37.32	[7]
11	Operation and Maintenace Expense with Increase	862,817		2,009	864,826		23	[3]	864,826		37.38	[8]
12												
13	Total Adjusted Depreciation and Amortization	960,468	[1]	-	960,468				960,468		0.00	[1]
14	Total Adjusted General Taxes	103,598	[1]	-	103,598				103,598		138.14	[1]
15	Total Adjusted Interest on Customer Deposits	7,971	[1]	-	7,971				7,971		137.50	[1]
16												
17	Net Income Taxes	45,506	[1]								8.05	[1]
18	Revenue Increase (L19)			125,327			1,130				-20.60	[7]
19	Income Taxes with Increase	45,506		125,327	170,833		1,130	[4]	170,825		-12.97	[8]
20												
21	Amortization of Investment Tax Credit	(3,614)	[1]	-	(3,614)				(3,614)		0.00	[1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,985,196		127,336	3,112,532		1,153		3,112,524		24.11	[9]
23												
24	Income for Return (L3 - L22)	375,813		416,925	792,738		5,071		792,704	[5]	22.91	[9]
25	Interest Expense	205,768	[1]	1,334	207,101		1,325		207,093	[6]	87.70	[1]
26	Return for Equity (L24 - L25)	170,045		415,592	585,636		3,746		585,611		0.00	[1]
27												
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009			$ 3,905,270				$ 3,905,228		23.86	[9]
29												
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,658,819	[1]	$ 69,087	$ 10,727,906		$ 68,629		$ 10,727,448			
31												
32	Overall Rate of Return (L24 / L30)	3.53%			7.39%				7.39%			
33	Target Rate of Return	7.39%	[2]		7.39%	[2]			7.39%	[2]		
34												
35				Revenue	Adjusted							
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted		Increase	w/Increase							
37	Annual Requirement (L3 and/or L28)	$ 3,361,009			$ 3,905,270				$ 3,905,228			
38	Daily Requirement (L37 / 365 Days)	$ 9,208			$ 10,699				$ 10,699			
39	Net Lag Days	13.64	[1]		18.19				18.19			
40												
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,582		$ 69,087	$ 194,669		$ 455		$ 194,666			
42	Add: Working Capital Related to NC Sales Tax	$ 4,760	[1]		$ 4,760	[1]						
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,342		$ 69,087	$ 199,429							

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Rebuttal

Line No.	Description	NC Re Financials Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	NC Retail Iteration 3 Increase (j) = (k) - (h)	With Increase (k) = (h) + (j)	Weighted Lead Lag Days (l)	
1	Total Adjusted Present Revenue	$ 3,361,009 [1]					42.09	[1]
2	Revenue Increase (L3)	-	544,261		41		41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009	544,261	3,905,270	41	3,905,270	42.06	[8]
4								
5	Operating Expenses:							
6	Fuel Used in Electric Generation	851,653 [1]	-	851,653		851,653	28.49	[1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44	[1]
8								
9	Operation & Maintenance Expense	862,817 [1]					37.38	[1]
10	Revenue Increase (L11)		2,009		0	23	37.32	[7]
11	Operation and Maintenace Expense with Increase	862,817	2,009	864,826	0 [3]	864,826	37.38	[8]
12								
13	Total Adjusted Depreciation and Amortization	960,468 [1]	-	960,468		960,468	0.00	[1]
14	Total Adjusted General Taxes	103,598 [1]	-	103,598		103,598	138.14	[1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50	[1]
16								
17	Net Income Taxes	45,506 [1]					8.05	[1]
18	Revenue Increase (L19)		125,327		7		-20.60	[7]
19	Income Taxes with Increase	45,506	125,327	170,833	7 [4]	170,833	-12.97	[8]
20								
21	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00	[1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,985,196	127,336	3,112,532	8	3,112,532	24.11	[9]
23								
24	Income for Return (L3 - L22)	375,813	416,925	792,738	34	792,738 [5]	22.91	[9]
25	Interest Expense	205,768 [1]	1,334	207,101	9	207,101 [6]	87.70	[1]
26	Return for Equity (L24 - L25)	170,045	415,592	585,636	25	585,636	0.00	[1]
27								
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009		$ 3,905,270		$ 3,905,270	23.86	[9]
29								
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,658,819 [1]	$ 69,087	$ 10,727,906	$ 455	$ 10,727,903		
31								
32	Overall Rate of Return (L24 / L30)	3.53%		7.39%		7.39%		
33	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]		
34								
35			Revenue	Adjusted				
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase				
37	Annual Requirement (L3 and/or L28)	$ 3,361,009		$ 3,905,270		$ 3,905,270		
38	Daily Requirement (L37 / 365 Days)	$ 9,208		$ 10,699		$ 10,699		
39	Net Lag Days	13.64 [1]		18.19		18.19		
40								
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,582	$ 69,087	$ 194,669	$ 3	$ 194,669		
42	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]				
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,342	$ 69,087	$ 199,429				

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Rebuttal

Line No.	Description	NC Re Financials: Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	NC Retail Iteration 4: Increase (m) = (n) - (k)	With Increase (n) = (k) + (m)	Weighted Lead Lag Days (o)
1	Total Adjusted Present Revenue	$ 3,361,009 [1]					42.09 [1]
2	Revenue Increase (L3)	-	544,261		0		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L22 + L24)	3,361,009	544,261	3,905,270	0	3,905,270	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	851,653 [1]	-	851,653		851,653	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	862,817 [1]					37.38 [1]
10	Revenue Increase (L11)		2,009		0	23	37.32 [7]
11	Operation and Maintenace Expense with Increase	862,817	2,009	864,826	0 [3]	864,826	37.38 [8]
12							
13	Total Adjusted Depreciation and Amortization	960,468 [1]	-	960,468		960,468	0.00 [1]
14	Total Adjusted General Taxes	103,598 [1]	-	103,598		103,598	138.14 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	45,506 [1]					8.05 [1]
18	Revenue Increase (L19)		125,327		0		-20.60 [7]
19	Income Taxes with Increase	45,506	125,327	170,833	0 [4]	170,833	-12.97 [8]
20							
21	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
22	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L21)	2,985,196	127,336	3,112,532	0	3,112,532	24.11 [9]
23							
24	Income for Return (L3 - L22)	375,813	416,925	792,738	0	792,738 [5]	22.91 [9]
25	Interest Expense	205,768 [1]	1,334	207,101	0	207,101 [6]	87.70 [1]
26	Return for Equity (L24 - L25)	170,045	415,592	585,636	0	585,636	0.00 [1]
27							
28	Total Requirement (L22 + L24 = L3)	$ 3,361,009		$ 3,905,270		$ 3,905,270	23.86 [9]
29							
30	Rate Base [CWC Solved for Through Iterative Process]	$ 10,658,819 [1]	$ 69,087	$ 10,727,906	$ 3	$ 10,727,906	
31							
32	Overall Rate of Return (L24 / L30)	3.53%		7.39%		7.39%	
33	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]	
34							
35			Revenue	Adjusted			
36	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
37	Annual Requirement (L3 and/or L28)	$ 3,361,009		$ 3,905,270			
38	Daily Requirement (L37 / 365 Days)	$ 9,208		$ 10,699			
39	Net Lag Days	13.64 [1]		18.19			
40							
41	Est. CWC Req. Before Sales Tax Requirement (L38 x L39)	$ 125,582	$ 69,087	$ 194,669			
42	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
43	Total Cash Working Capital Requirements (L41 + L42)	$ 130,342	$ 69,087	$ 199,429			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L26 / (1 - Tax Rate) - L26
[5] Line 30 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Rebuttal

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
1	**Rate Schedule Revenue**								
2	Rate Revenues	$ 3,575,788		$ 3,575,788			41.88		41.88
3	Total Revenue Lag Sales for Resale	134,915		134,915			33.73		33.73
4	Provisions For Rate Refunds	(104,546)		(104,546)			41.88		41.88
5	Forfeited Discounts	7,664		7,664			72.30		72.30
6	Miscellaneous Revenues	5,506		5,506			76.00		76.00
7	RENT - (454) - DIST PLT REL	4,466		4,466			41.63		41.63
8	RENT - (454) - DIST POLE RENTAL REV	10,901		10,901			182.00		182.00
9	RENT - (454) - TRANS PLT REL	382		382			41.63		41.63
10	RENT - (454) - ADD FAC - WHLS	-		-			0.00		0.00
11	RENT - (454) - ADD FAC - RET X LIGHTING	4,617		4,617			41.63		41.63
12	RENT - (454) - ADD FAC - LIGHTING	3,849		3,849			41.63		41.63
13	RENT - (454) - OTHER	3,413		3,413			68.21		68.21
14	OTHER ELEC REV (456) - PROD PLT REL	10,549		10,549			41.88		41.88
15	NC-0100 Annualize Retail revenues for current rates		(201,667)	(201,667)				41.88	41.88
16	NC-0300 Normalize for weather		(72,510)	(72,510)				41.88	41.88
17	NC-0400 Annualize revenues for customer growth		(2,159)	(2,159)				41.88	41.88
18	NC-0500 Eliminate unbilled revenues		11,826	11,826				41.88	41.88
19	NC-0600 Adjust costs recovered through non-fuel riders		(27,830)	(27,830)				41.88	41.88
20	NC-2900 Storm Deferral NC FMD		-	-				41.88	41.88
21	NC-3000 Adjust Other Revenue		(4,155)	(4,155)				98.96	98.96
22	Rounding		-	-				41.88	41.88
23	Revenue - Adjustments (Sum Lines 15 through 22)	-	(296,495)	(296,495)					
24									
25	Total Adjusted Revenue (L2 + L23)	$ 3,657,503	$ (296,495)	$ 3,361,009	$ -	$ 3,361,009	42.13	(0.05)	42.09
26									
27	**Operating Expenses:**								
28	Fuel Used in Electric Generation								
29	OM Prod Energy - Fuel	$ 863,120		$ 863,120			28.49		28.49
30	RECS Consumption Expense	18,522		18,522			28.49		28.49
31	NC-0200 Update fuel costs to approved rate		11,436	11,436				28.49	28.49
32	NC-0300 Normalize for weather		(20,432)	(20,432)				28.49	28.49
33	NC-0400 Annualize revenues for customer growth		(2,471)	(2,471)				28.49	28.49
34	NC-0600 Adjust costs recovered through non-fuel riders		(18,522)	(18,522)				28.49	28.49
35	NC-2900 Storm Deferral NC FMD		-	-				28.49	28.49
36	Rounding		-	-				28.49	28.49
37	Fuel Used in Electric Generation - Adjustments (Sum Lines 31 through 36)	-	(29,989)	(29,989)					
38									
39	Total Adjusted Fuel Used in Electric Generation (L29 + L37)	$ 881,642	$ (29,989)	$ 851,653	$ -	$ 851,653	28.49	0.00	28.49
40									
41	Purchased Power								
42	OM PROD PURCHASES - CAPACITY COST	$ 67,280		$ 67,280			30.29		30.29
42	OM PROD PURCHASES - ENERGY COST	365,384		365,384			30.29		30.29
43	OM DEFERRED FUEL EXPENSE	(273,901)		(273,901)			28.49		28.49
43	NC-3500 Adjust purchased power		(1,965)	(1,965)				30.29	30.29
44	Rounding		-	-					
45	Purchased Power - Adjustments (Sum Lines 43 through 44)	-	(1,965)	(1,965)					
46									
47	Total Adjusted Purchased Power (L42 + L45)	$ 158,763	$ (1,965)	$ 156,798	$ -	$ 156,798	33.40	0.04	33.44
48									

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Rebuttal

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
49	Operation & Maintenance Expense								
50	Total Labor Expense	$ 430,295		$ 430,295			37.07		37.07
46	Pension and Benefits	76,271		76,271			13.97		13.97
47	Regulatory Commission Expense	7,038		7,038			93.25		93.25
48	Property Insurance	(526)		(526)			(222.30)		(222.30)
49	Injuries & Damages - Workman's Compensation	197		197			0.00		0.00
50	Uncollectible Accounts	8,937		8,937			0.00		0.00
51	Remaining Other Oper & Maint Expense	528,607		528,607			40.52		40.52
51	NC-0100 Annualize Retail revenues for current rates		(744)	(744)				37.32	37.32
52	NC-0200 Update fuel costs to approved rate		-	-				37.32	37.32
53	NC-0300 Normalize for weather		(268)	(268)				37.32	37.32
54	NC-0400 Annualize revenues for customer growth		(8)	(8)				37.32	37.32
55	NC-0600 Adjust costs recovered through non-fuel riders		(136,143)	(136,143)				37.32	37.32
56	NC-0700 Adjust O&M for executive compensation		(2,399)	(2,399)				37.07	37.07
57	NC-1200 Annualize O&M non-labor expenses		4,241	4,241				33.30	33.30
58	NC-1300 Normalize O&M labor expenses		(19,794)	(19,794)				37.07	37.07
59	NC-1400 Update benefits costs		(6,358)	(6,358)				13.97	13.97
60	NC-1500 Levelize nuclear refueling outage costs		(6,190)	(6,190)				40.52	40.52
61	NC-1600 Amortize rate case costs		701	701				0.00	0.00
62	NC-1700 Adjust aviation expenses		(1,452)	(1,452)				37.32	37.32
63	NC-1800 Adjust for approved regulatory assets and liabilities		1,603	1,603				0.00	0.00
64	NC-1900 Adjust for Merger Related Costs		(4,039)	(4,039)				37.32	37.32
65	NC-2000 Amortize Severance Costs		(24,140)	(24,140)				37.07	37.07
66	NC-2500 Adjust for credit card fees		5,269	5,269				40.52	40.52
67	NC-2700 Adjust vegetation management expenses		5,757	5,757				40.52	40.52
68	NC-2900 Storm Deferral NC		-	-				37.32	37.32
69	NC-3000 Adjust Other Revenue		(5)	(5)				37.32	37.32
70	NC-3100 Adjust for change in NCUC Reg Fee		(234)	(234)				93.25	93.25
71	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(6,413)	(6,413)				37.32	37.32
72	NC-3300 Adjust for CertainTeed payment Obligation		-	-				37.32	37.32
73	NC-3400 Amortize deferred balance Asheville Combined Cycle		2,613	2,613				37.32	37.32
74			-	-				0.00	0.00
75	Rounding		-	-				33.30	33.30
76	Operation & Maintenance Expense - Adjustments (Sum Lines 51 through 72)	-	(188,002)	(188,002)					
77									
78	Total Adjusted Operation & Maintenance Expense (L50 + L76)	$ 1,050,819	$ (188,002)	$ 862,817	$ -	$ 862,817	37.32	0.07	37.38
79									
80	Depreciation and Amortization	$ 669,787		$ 669,787			0.00		0.00
81	NC-0200 Update fuel costs to approved rate		-	-				0.00	0.00
82	NC-0600 Adjust costs recovered through non-fuel riders		(58,446)	(58,446)				0.00	0.00
83	NC-0800 Annualize Depreciation on year end plant balances		41,407	41,407				0.00	0.00
84	NC-1000 Adjust for post test year additions to plant in service		62,826	62,826				0.00	0.00
85	NC-1100 Amortize deferred environmental costs		96,023	96,023				0.00	0.00
86	NC-1800 Adjust for approved regulatory assets and liabilities		(3,479)	(3,479)				0.00	0.00
87	NC-1900 Adjust for Merger Related Costs		(182)	(182)				0.00	0.00
88	NC-2600 Adjust for Depreciation for new rates		88,728	88,728				0.00	0.00
89	NC-2800 Adjust reserve for end of life nuclear costs		(91)	(91)				0.00	0.00
90	NC-2900 Storm Deferral		43,201	43,201				0.00	0.00
91	NC-3200 Reflect retirement of Asheville Steam Generating Plant		10,201	10,201				0.00	0.00
92	NC-3400 Amortize deferred balance Asheville Combined Cycle		10,493	10,493				0.00	0.00
93	Rounding		-	-					
94	Depreciation and Amortization - Adjustments (Sum Lines 81 through 93)	-	290,680	290,680					
95									
96	Total Adjusted Depreciation and Amortization (L80 + L94)	$ 669,787	$ 290,680	$ 960,468	$ -	$ 960,468	0.00	0.00	0.00
97									

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Rebuttal

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
98	General Taxes								
99	Payroll Taxes	$ 26,288		$ 26,288			48.41		48.41
100	Property Tax	68,133		68,133			186.50		186.50
101	FED HEAVY VEHICLE USE TAX	48		48			0.00		0.00
102	ELECTRIC EXCISE TAX - SC	-		-			0.00		0.00
103	PRIVILEGE TAX	12,244		12,244			(11.97)		(11.97)
104	MISC TAX - NC	(4,517)		(4,517)			60.00		60.00
105	MISC TAX - SC & OTHER STATES	1		1			129.46		129.46
106	PUC LICENSE TAX - SC	-		-			0.00		0.00
107	NC-0600 Adjust costs recovered through non-fuel riders		(6,458)	(6,458)				137.26	137.26
108	NC-0900 Annualize property taxes on year end plant balances		4,064	4,064				186.50	186.50
109	NC-1000 Adjust for post test year additions to plant in service		5,023	5,023				186.50	186.50
110	NC-1300 Normalize O&M labor expenses		(1,162)	(1,162)				48.41	48.41
111	NC-1700 Adjust aviation expenses		(18)	(18)				48.41	48.41
112	NC-1800 Adjust for approved regulatory assets and liabilities		5	5				48.41	48.41
113	NC-1900 Adjust for Merger Related Costs		(53)	(53)				48.41	48.41
114	NC-3200 Reflect retirement of Asheville Steam Generating Plant		-	-				186.50	186.50
115	Rounding		-	-					
116	General Taxes - Adjustments (Sum Lines 107 through 115)	-	1,401	1,401					
117									
118	Total Adjusted General Tax (L99 + L116)	$ 102,197	$ 1,401	$ 103,598	$ -	$ 103,598	132.70	5.43	138.14
119									
120	Interest on Customer Deposits	$ 7,971		$ 7,971			137.50		137.50
121	Interest on Customer Deposits - Adjustments			-					
122	Rounding		-	-					
123	Total Adjusted Interest on Customer Deposits (L120 + L121)	$ 7,971	$ -	$ 7,971	$ -	$ 7,971	137.50	0.00	137.50
124									
125	Income Taxes								
126	Federal Income Tax	$ (49,091)		$ (49,091)			44.75		44.75
127	State Income Tax	(2,917)		(2,917)			44.75		44.75
128	Income Tax - Deferred	164,994		164,994			0.00		0.00
129	PF INC TAX-Adjust Income Taxes		(129,831)	(129,831)				(20.60)	(20.60)
130	NC-0600 Adjust costs recovered through non-fuel riders		63,168	63,168				0.00	0.00
131	NC-2100 Adjust NC income taxes for rate change		(2,183)	(2,183)				(20.60)	(20.60)
132	NC-2200 Synchronize interest expense		1,271	1,271				(20.60)	(20.60)
133	Rounding		-	-					
134	Income Taxes - Adjustments (Sum Lines 129 through 133)	-	(67,575)	(67,575)					
135									
136	Total Adjusted Income Taxes (L126 + L134)	$ 112,986	$ (67,575)	$ 45,411	$ 95 [5]	$ 45,506	(20.60)	28.65	8.05
137									
138	Amortization of Investment Tax Credit	$ (2,134)		$ (2,134)			0.00		0.00
139	NC-0800 Annualize Depreciation on year end plant balances		(1,481)	(1,481)				0.00	0.00
140	Rounding		-	-					
141	Amort. of Investment Tax Credit - Adjustments (Sum Lines 139 through 140)	-	(1,481)	(1,481)					
142									
143	Total Adjusted Amortization of Investment Tax Credit (L138 + L141)	$ (2,134)	$ (1,481)	$ (3,614)	$ -	$ (3,614)	0.00	0.00	0.00
144									
145	Total Operating Expense (L39+L47+L78+L96+L118+L123+L136+L143)	$ 2,982,032	$ 3,070	$ 2,985,101	$ 95	$ 2,985,196	27.48	(1.51)	25.97
146									
147	Income for Return (L25 - L145)	675,472	(299,564)	375,907	(95)	375,813	27.48	20.62	48.10
148	Interest Expense	211,661	(5,484)	206,177 [4]	(410) [4]	205,768	87.70	0.00	87.70 [1]
149	Return for Equity (L147 - L148)	463,810	(294,080)	169,730	315	170,045	0.00	0.00	0.00 [1]
150									
151	Total Requirement (L145 + L147 = L25)	$ 3,657,503		$ 3,361,009		$ 3,361,009	27.48	0.96	28.45 [6]
152									
153	RATE BASE	$ 9,859,050 [3]	$ 820,988	$ 10,680,038 [3]	$ (21,219)	$ 10,658,819			
154									
155	Overall Rate of Return (L147 / L153)	6.85%		3.52%		3.53%			

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Rebuttal

		NC Retail													
		Financials								Lead Lag Days					
Line No.	Description	Per Books	[1]	Adjustments	[3]	Adjusted Before Change in CWC	[3]	Change in CWC	Adjusted with CWC	Per Books	[1]	Adjustments	[1]	Adjusted Before Increase	[6]
		(a)		(b)		(c) = (a) + (b)		(d)	(e) = (c) + (d)	(f)		(g)		(h) = (f) + (g)	

Duke Energy Progress, LLC NC-2302
Docket No. E-2, Sub 1219 Rebuttal
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
156									
157			Change						
158	Calculation of Change in Cash Working Capital (CWC) due to Adjustments	Per Books	in CWC	Adjusted					
159	Revenue Lag Days	42.13		42.09					
160	Requirement Lead Days	27.48		28.45					
161									
162	Net Lag Days (L159 - L160)	14.65		13.64					
163									
164	Annual Requirement	$ 3,657,503		$ 3,361,009					
165	Daily Requirement (L164 / 365 Days)	$ 10,021		$ 9,208					
166	Net Lag Days (L162, Rounded Per Books)	14.65		13.64					
167	Est. CWC Req. Before Sales Tax Requirement (L165 x L166)	$ 146,801		$ 125,582					
168									
169	Add: Working Capital Related to NC Sales Tax	$ 4,760 [2]		$ 4,760 [2]					
170									
171	Total Cash Working Capital Requirements (L167 + L169)	$ 151,561	$ (21,219)	$ 130,342					

Notes:
[1] NC 2305: Revised Lead Lag Study (E-1 Item 14)
[2] NC 2303 Summary
[3] Docket No. E-2, Sub 1219, Smith Exhibit 1 Rebuttal
[4] Rate Base x NC-2304-Inputs
[5] Interest Expense: - L148 x Tax Rate: 23.1693%
[6] New weighted averages calculated.

NC-2303
Rebuttal

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the test period ended December 31, 2018
Dollars in Thousands

Revised E-1 Item 14

Line No	Description		Actual Annual Expense	Lead (Lag) Days		Weighted Amount
			[A]	[B]		[C]
	Calculation of NC Retail Amount:					
1	Total Revenue Lag	$	(3,657,503)	42.13	$	(154,105,865)
2						
3	Operation & Maintenance Expense	$	2,091,224	33.30	$	69,630,312
4	Depreciation and Amortization		669,787	0.00		-
5	Taxes Other Than Income Taxes		102,197	132.70		13,561,920
6	Interest on Customer Deposits		7,971	137.50		1,096,011
7	Net Income Taxes		112,986	-20.60		(2,327,337)
8	ITC		(2,134)	0.00		-
9	Income for Return		675,472	27.48		18,562,554
10	Total Requirements (Sum L3:L9)	$	3,657,503	27.48	$	100,523,460
11						
12	Revenue Lag Days (L1)			42.13		
13	Requirements Lead Days (-L10)			-27.48		
14	Net Lag Days (L12 + L13)			14.65		
15	Daily Requirements (Line 9, Col. A divided by 365)				$	10,020.56
16						
17	Estimated Cash Working Capital Requirements (L14 x L15)				$	146,801
18	Add: Cash Working Capital Related to NC Sales Tax					4,760
19	Total Cash Working Capital Requirements (L17 + L18)				$	151,561
20						
21	**Calculation of Total Company and Jurisdictional Amounts:**					
22	NC Retail Factor					67.0949% [1]
23						
24	Total Company Cash Working Capital Requirements (L19 / L22)				$	225,890
25						

[1] NC Retail Allocation Factor - Net Book Plant

Duke Energy Progress, LLC NC-2304
Docket No. E-2, Sub 1219 Rebuttal
Adjustment to Cash Working Capital - Input Worksheet
For the test period ended December 31, 2018

Line No	Description	Rate		Ratio		Weighted	
1	Debt	4.11%	[1]	47.00%	[1]	1.9305%	[2]
2	Equity	10.30%	[1]	53.00%	[1]	5.4590%	[3]
3	Total ROR (L1 + L2)					7.3895%	
4							
5	Statutory tax rate	23.1693%	[4]				
6	Statutory regulatory fee percentage rate	0.1297%	[5]				
7	Uncollectibles rate	0.24%	[6]				

Notes:
[1] Smith Exhibit 1, Page 2
[2] Debt Rate x Debt Ratio
[3] ROE x Equity Ratio
[4] NC-0104 - 2019 Tax Rate, Line 10
[5] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate, Docket No. M-100, Sub 142
[6] NC-0105 - Development of Uncollectibles Rate

Supplemental E-1 Item 14

NC-2305
Rebuttal

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018
#NAME?

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	1	**OPERATING REVENUES:**						
	2							
	3							
Calc	4	Service Lag				15.21	A	
	5	Billing Lag						
1	6	Total Retail Sales & Billing Lag		(4,156,399,663)	(3,563,165,280)	1.66	A	
	7	Revenue - REPS		(24,719,022)	(24,719,022)			
	8	Unbilled Revenue	0440.99, 0442.19, 0442.29, 0444.99, 0445.09	13,507,473	12,096,317			
	9							
2	10	Collection Lag				25.01	A	
	11							
	12	Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17)		(4,167,611,212)	(3,575,787,985)	41.88		(149,748,041,162)
	13							
3	14	Total Revenue Lag Sales for Resale		(1,511,358,381)	(134,915,331)	33.73	A	(4,550,694,117)
	15	Provisions For Rate Refunds	0449	118,958,671	104,545,765	41.88	B	4,378,202,395
	16	Total Sales of Electricity (L12 through L14)		(5,560,010,922)	(3,606,157,551)	41.57		(149,920,532,884)
	17							
	18	Other Revenues:						
	19	Forfeited Discounts	0450100, 0450200	(8,582,371)	(7,663,772)	72.30	A	(554,090,707)
4c	20	Miscellaneous Revenues	0451100	(6,165,627)	(5,505,700)	76.00		(418,433,189)
4d	21	RENT - (454) - DIST PLT REL		(5,124,157)	(4,465,630)	41.63		(185,904,174)
4d	22	RENT - (454) - DIST POLE RENTAL REV		(12,960,572)	(10,901,069)	182.00		(1,983,994,633)
4d	23	RENT - (454) - TRANS PLT REL		(639,579)	(381,636)	41.63		(15,887,522)
4d	24	RENT - (454) - ADD FAC - WHLS		(2,806,145)	0	0.00		-
4d	25	RENT - (454) - ADD FAC - RET X LIGHTING		(5,162,072)	(4,617,085)	41.63		(192,209,244)
4d	26	RENT - (454) - ADD FAC - LIGHTING		(4,184,534)	(3,848,777)	41.63		(160,224,580)
4d	27	RENT - (454) - OTHER		(5,086,652)	(3,412,883)	68.21		(232,798,642)
	28	OTHER ELEC REV (456) - PROD PLT REL		(1,924,556)	(1,184,137)	41.88		(49,589,686)
	29	OTHER ELEC REV (456) - TRANS REL		(10,403,096)	(6,207,517)	41.88		(259,960,449)
	30	OTHER ELEC REV (456) - GEN PLT REL		0	0	41.88		-
	31	OTHER ELEC REV (456) - WH D/A		(55,825,581)	0	41.88		-
	32	OTHER ELEC REV (456) - OTHER		(548,940)	(368,310)	41.88		(15,424,225)
	33	OTHER ELEC REV (456) - REPS		(1,114,245)	(1,114,245)	41.88		(46,662,737)
	34	OTHER ELEC REV (456) - OTHER ENERGY		0	0	41.88		-
	35	OTHER ELEC REV (456) - DIST PLT REL	0456630	(1,611,605)	(1,404,491)	41.88		(58,817,730)
	36	REV - OTHER NC RETAIL SPECIFIC		(270,645)	(270,645)	41.88		(11,334,162)
	37	Total Other Revenues (L19 through L36)		(122,410,378)	(51,345,897)	81.51		(4,185,331,681)
	38							-
	39	**Utility Oper Revenues (L16 + L37)**	#	(5,682,421,300)	(3,657,503,448)	42.13		(154,105,864,564)

Supplemental E-1 Item 14

NC-2305
Rebuttal

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018
#NAME?

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
	40	ELECTRIC OPERATING REVENUE	#	5,682,421,300	3,657,503,448		
	41						

Supplemental E-1 Item 14

NC-2305
Rebuttal

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018
#NAME?

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	42	**OPERATION AND MAINTENANCE EXPENSE:**						
	43							
5 + 6	44	**Fuel Used in Electric Generation**						
	45	OM Prod Energy - Fuel		1,410,621,869	863,120,481	28.49	A	24,588,906,214
	46	RECS Consumption Expense		18,521,748	18,521,748	28.49	A	527,654,628
	47	**Fuel Used in Elec Gen (HFM Greenbook I/S)**	F_FUEL_USED_ELEC_GEN	**1,429,143,617**	**881,642,228**	**28.49**		**25,116,560,842**
7	48							
7	49	OM PROD PURCHASES - CAPACITY COST		109,348,837	67,279,932	30.29	A	2,037,909,147
	50	OM PROD PURCHASES - ENERGY COST		597,919,200	365,384,360	30.29	A	11,067,492,256
	51	OM DEFERRED FUEL EXPENSE	0557980	(316,590,958)	(273,901,174)	28.49	C	(7,803,001,349)
	52	**Purchased Power (Acct 555) + Def Fuel (Acct 557)**	0555XXX	**390,677,079**	**158,763,118**	**33.40**		**5,302,400,054**
	53							
	54	**Total Other O&M Excluding Fuel and Purchased Power**						
9	55							
	56	Total Labor Expense		649,874,113	430,294,724	37.07	A	15,951,025,410
8	57							
	58	Pension and Benefits	0926XXX	115,350,507	76,270,687	13.97	A	1,065,501,492
10	59							
	60	Regulatory Commission Expense	0928000	8,592,296	7,037,696	93.25	A	656,265,126
11	61							
	62	Property Insurance	0924XXX	(774,442)	(525,984)	(222.30)	A	116,926,247
15	63							
	64	Injuries & Damages - Workman's Compensation	0925980	290,241	197,125	0.00	A	-
	65							
	66	Uncollectible Accounts	0904000, 0904001	10,008,548	8,937,301	0.00	A	-
	67							
	68	Remaining Other Oper & Maint Expense		763,377,394	528,607,218	40.52	D	21,421,632,363
	69							
	70	Total O&M Excl. Fuel and Purch. Power		1,546,718,656	1,050,818,766	37.32		39,211,350,637
	71							
	72	**Total Operation and Maintenance Expense (L47 + L52 + L70)**		**3,366,539,352**	**2,091,224,112**	**33.30**		**69,630,311,534**
	73							
	74	Total Depreciation & Amortization & Property Loss		1,060,260,424	669,787,484	0.00	A	-
	75							
	76	**Taxes Other Than Income Taxes**						
	77	Payroll Taxes		39,721,091	26,288,326	48.41	A	1,272,617,860
9	78	Property Tax		101,157,752	68,132,745	186.50		12,706,756,958
13	79	FED HEAVY VEHICLE USE TAX		61,024	48,458	0.00		-
	80	ELECTRIC EXCISE TAX - SC		2,222,093	0	0.00		-
	81	PRIVILEGE TAX		16,355,581	12,243,595	(11.97)		(146,555,834)
13	82	MISC TAX - NC		-6,034,064	-4,517,029	60.00	E	(271,021,743)

Supplemental E-1 Item 14

NC-2305
Rebuttal

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018
#NAME?

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018		NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	83	MISC TAX - SC & OTHER STATES		-165		949	129.46	A	122,893
	84	PUC LICENSE TAX - SC		-121,100		0	0.00	A	-
	85	Taxes Other Than Income Taxes		153,362,212		102,197,044	132.70		13,561,920,134
16	86								
	87	Total Interest on Customer Deposits		8,642,928		7,970,989	137.50	A	1,096,011,021
14	88								
14	89	Federal Income Tax		(66,292,963)		(49,091,019)	44.75	A	(2,196,823,118)
	90	State Income Tax		(3,938,471)		(2,916,502)	44.75		(130,513,463)
	91	Income Tax - Deferred		220,852,977		164,993,723	0.00		-
	92	Net Income Taxes		150,621,543		112,986,202	(20.60)		(2,327,336,581)
	93								
	94	Investment of Tax Credit Adj Net	04114XX	(3,355,660)		(2,133,914)	0.00	A	-
	95								
	96	**Total Utility Operating Expenses (L72 + L74 + L85 + L87 + L92 + L94)**		4,736,070,798		2,982,031,917	27.48		81,960,906,108
	97								
	98	Interest Expense for Electric Operations		315,465,770		211,661,368	87.70	F	18,562,553,881
	99	Income for Equity Return (L100 - L198)		630,884,732		463,810,163	0.00	A	-
	100	Net Operating Income		946,350,502		675,471,531	27.48		18,562,553,881
	101								
	102	**Total Requirements (L96 + L100)**		5,682,421,300		3,657,503,448	27.48		100,523,459,988
	103								
	104								
	105	**Cash Working Capital Related to NC Sales Tax**		4,759,823	G				

	Tickmark Legend
A	Lead/lag days was obtained from Lead/Lag study performed by Ernst & Young. See the Appendix in the Duke Lead Lag Report - DEP file.
B	Revenue refund will be returned through another mechanism; number set to Revenue Lag Days to eliminate effect on Cash Working Capital.
C	Lead/lag days for fuel is being used for this line item to faciliate elimination of this item with the adjustments to cash working capital being proposed in this rate case.
D	Remaining O&M for 2018 includes both nuclear fees and other O&M lines from the 2017 lead/lag study. Lead/lag days reflected is the weighted average of the amounts for those line items from the 2017 study.
E	This expense category is a new breakout for 2018. Lead/lag days was determined based on review of activity for 2018. A majority of the balance is related to a refund which was accrued in March and received in May. As such, a 60 day lag seems reasonable.
F	See 2017 Interest Lead Days tab for calculation.
G	Cash Working Capital Related to NC Sales Tax for 2018 was calculated on Schedule 17.

Supplemental E-1 Item 14

NC-2305
Rebuttal

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018
#NAME?

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount

Duke Energy Progress, LLC NC-2500
Docket No. E-2, Sub 1219 Rebuttal
Adjust for credit card fees
For the test period ended December 31, 2018

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expenses for credit card fees costs by projecting 2019 transactions and applying a unit cost per transaction.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update:

NC-2503 - credit card transaction actuals updated through October 2019. The formula in line 18 has also been updated to account for 10 months of actuals vs 9 months of actuals.

November Update

An issue was identified with the previously reported 2019 actuals, therefore NC-2503 has been updated with revised actuals through November 2019. The formula in line 18 has also been updated to account for 11 months of actuals vs 10 months of actuals.

December update:

NC-2503 - credit card transaction actuals update through December 2019. The formula in line 18 has also been updated to account for 12 months of actuals.

January update:

NC-2503 - credit card transaction actuals update through January 2020. Line 18 reflects 13 months average times 12 months; Updated schedule titles to reflect actuals

February update:

NC-2503 - credit card transaction actuals update through February 2020. Line 18 reflects 14 months average times 12 months

Rebuttal

Adjusted NC-2503 for O&M transaction costs of $0.08 included in COS based on the cost of processing a check.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for credit card fees
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2500
Rebuttal

Line No.	Description	Source	Rebuttal	Total NC Retail Application	Change
1					
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-2501	5,269	5,197	72
11	Depreciation and amortization		-	-	-
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2501	(1,221)	(1,204)	(17)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	4,048	3,993	55
18					
19	Operating income	L4 - L17	$ (4,048)	$ (3,993)	$ (55)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35					
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for credit card fees
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2501
Rebuttal

Line No.	Description		Total NC Retail	
1	Impact to Income Statement Line Items			
2	Projected NC costs			
3	Credit card fees	$	5,307	[1]
4	Adjustment to O&M transaction costs included in COS		(38)	[3]
5	Impact to O&M (L3 + L4)	$	5,269	
6				
7	Statutory tax rate		23.1693%	[2]
8	Impact to income taxes (-L5 x L7)	$	(1,221)	
9				
10	Impact to operating income (-L5 - L8)	$	(4,048)	
11				
12				
13	Impact to Rate Base Line Items			
14	Accumulated depreciation and amortization:			
15	Impact to accumulated depreciation	$	-	
16				
17	Working capital investment:			
18		$	-	
19				
20	Impact to working capital investment (L18)	$	-	
21				
22	Deferred tax rate		23.1693%	
23	Impact to accumulated deferred income tax (-L20 x L22)	$	-	
24				
25	Impact to rate base (L15 + L20 + L23)	$	-	

[1] NC-2502 - Duke Energy Progress - Projected credit card fees - NC Retail
[2] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[3] NC-2503 - 2019 Credit/debit card and ACH transactions - NC Residential Only, Line 24

Duke Energy Progress, LLC | NC-2502
Docket No. E-2, Sub 1219 | Rebuttal
Adjust for credit card fees
For the test period ended December 31, 2018

Duke Energy Progress - Projected credit card fees - NC Retail

Line No.		Transactions NC Residential		Cost per transaction		NC Residential Projected costs
1						
2	Annualized Transactions	3,538,318	[1]	$ 1.50	[2]	5,307,477
3	Total					$ 5,307,477

[1] NC-2503 - Annualized Credit/debit card and ACH transactions - NC Residential Only
[2] Contracted 3rd party fee

Duke Energy Progress, LLC | NC-2503
Docket No. E-2, Sub 1219 | Rebuttal
Adjust for credit card fees
For the test period ended December 31, 2018

Annualized credit/debit card and ACH transactions - NC Residential Only

Line No.	Description	Total NC Retail
1	Actual NC Residential Transactions:	
2	Jan 2019	$ 276,317
3	Feb 2019	273,538
4	Mar 2019	293,409
5	Apr 2019	297,519
6	May 2019	289,174
7	Jun 2019	267,588
8	Jul 2019	310,976
9	Aug 2019	293,713
10	Sep 2019	301,097
11	Oct 2019	314,811
12	Nov 2019	278,484
13	Dec 2019	321,327
14	Jan 2020	320,258
15	Feb 2020	289,827
16	Total NC Residential Transactions (L2 through L15)	4,128,038 [1]
17		
18	Annualized transactions based on actuals Jan 2019 through Feb 2020 (L16 x (12/14)	3,538,318
19		
20	2018 NC residential credit card transactions	3,060,671
21	Increase in annualized NC residential credit card transactions (L18 - L20)	477,647
22		
23	Payment processing cost per transaction - checks	0.08
24	Adjustment to O&M transaction costs included in COS (L21 x L23)	38,212

[1] Number of transactions and payment processing costs provided by Revenue Services

Duke Energy Progress, LLC NC-3200
Docket No. E-2, Sub 1219 Rebuttal
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts operation and maintenance expenses, income taxes, depreciation and amortization expense, electric plant in service and accumulated depreciation associated with the retirement of the Asheville Steam Electric Generating Plant in January 2020. It also adjusts for the regulatory asset established as a result of the early retirement, which was originally planned for December 2027.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October Update
NC-3205 Line 6 - corrected statutory tax rate; NC-3207 - Lines 2-5 corrected to update latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results.

November Update
Corrected typo on date of expected retirement

December Update
NC-3204 - Updated retirement date if December 2019 to January 2020; NC-3206 - Changes as a result of updates to NC-3207 noted below; NC-3207 - Lines 2-5 corrected to update latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results.

January Update
NC-3204 - Changed forecasted February 2020 plant in service balance back to original filing - to update actuals in February 2020; NC-3206 - Changes due to updates to NC-3207; NC-3207 - Lines 2-5 reflect latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results

February Update
NC-3201 - Updated Lines 18 and 21 to zero out plant in service and accumulated depreciation balances. Amounts are reflected in NC-1000; Line 26 reflects actual inventory retired; NC-3204 - Forecasted plant in service and accumulated depreciation balances eliminated. Amounts reflected in NC-1000; NC-3206 Changes due to updates to NC-3207; NC-3207 - Lines 2-5 reflect latest estimate to remaning net book value of Asheville plant at retirement as a result of actual results.

Note: Plant in service and accumulated depreciation related to Asheville Steam Electric Generating plant was retired and reclassified to a regulatory asset in January 2020, with true-up adjustments in February 2020. The impacts of the retirement are included in actual plant in service data in NC-1000. NC-3200 has been updated to exclude impacts to plant in service and accumulated depreciation balances as a reuslt of the retirement.

Rebuttal:
Updated NC-3203 to account for depreciation expense and property tax accounted for in NC-1000, Lines 18 and 104.

Duke Energy Progress, LLC NC-3200
Docket No. E-2, Sub 1219 Rebuttal
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Source	Total NC Retail Rebuttal	Application	Change
1			Rebuttal	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expens	NC-3201	(6,413)	(6,413)	-
11	Depreciation and amortization	NC-3201	10,201	(181)	10,381
12	General taxes	NC-3201	-	(1,032)	1,032
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-3201	(878)	1,767	(2,644)
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 thru L15	2,910	(5,859)	8,769
18					
19	Operating income	L4 - L17	$ (2,910)	$ 5,859	$ (8,769)
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-3201	$ -	$ (287,052)	$287,052
29	Accumulated depreciation and amortization	NC-3201	-	210,671	(210,671)
30	Electric plant in service, net	Sum L28 thru L29	-	(76,381)	76,381
31					
32	Add:				
33	Materials and supplies		(7,076)	(7,002)	(73)
34	Working capital investment		64,590	65,929	(1,339)
35					
36					
37	Less:				
38	Accumulated deferred taxes		(14,965)	(15,275)	310
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 thru L42	$ 42,550	$ (32,730)	$ 75,279
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3200
Rebuttal

Line No.	Description	Total System	NC Retail Allocation	Total NC Retail
1	Remove Direct O&M - Demand Related	$ (2,423) [1]	61.5278% [2]	$ (1,491) [1]
2	Remove Direct O&M - Energy Related	(8,055) [1]	61.1093% [5]	(4,923) [1]
3	Impact to O&M (L1 + L2)	$ (10,478)		$ (6,413)
4				
5	Remove Depreciation related to Asheville Steam Electric Generating Plant	$ 3 [3]	61.5278% [2]	$ 2
6	Amortize retired Asheville Steam Electric Generating Plant	16,575 [4]	61.5278% [2]	10,198
7	Impact to Depreciation and Amortization (L5 + L6)	$ 16,579		$ 10,201
8				
9	Remove Property Taxes	$ - [3]	61.5278% [2]	$ -
10	Impact to general taxes (L9)	$ -		$ -
11				
12	Statutory tax rate	23.1693% [6]		23.1693% [6]
13	Impact to income taxes (-(L3 + L7 + L10) x L12)	$ (1,414)		$ (878)
14				
15	Impact to operating income (-L3 - L7 - L10 - L13)	$ (4,687)		$ (2,910)
16				
17	Rate Base investment:			
18	Remove Asheville Steam Electric Plant in Service	$ - [3]	61.5278% [2]	$ -
19	Remove Total Asheville Steam Electric Generating Plant Electric Plant in Service (L18)	$ -		$ -
20				
21	Remove Asheville Steam Electric Generating Plant Accumulated Depreciation	$ - [3]	61.5278% [2]	$ -
22	Remove Total Asheville Steam Electric Generating Plant Accumulated Depreciation (L21)	$ -		$ -
23				
24	Impact to net plant investment (L19 + L22)	$ -		$ -
25				
26	Remove Asheville Steam Electric Generating Plant Inventory balance at retirement	$ (10,418) [7]	67.9178% [8]	$ (7,076)
27	Impact to materials and supplies (L26)	$ (10,418)		$ (7,076)
28				
29	Regulatory Asset - Retired Asheville Steam Electric Generating Plant	$ 104,977 [4]	61.5278% [2]	$ 64,590
30	Impact to working capital investment (L29)	$ 104,977		$ 64,590
31				
32	Deferred tax rate	23.1693% [6]		23.1693% [6]
33	Impact to accumulated deferred income tax (-L30 x L32)	$ (24,323)		$ (14,965)
34				
35	Impact to rate base (L30 + L27 + L24 + L33)	$ 70,237		$ 42,550

[1] NC-3202 - Asheville Steam Electric Generating Plant Operating and Maintenance Expenses
[2] NC Retail Allocation Factor - DPALL
[3] NC-3203 - Asheville Steam Electric Generating Plant Asset Impacts in Proformas and the Test Year
[4] NC-3205 - Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization
[5] NC Retail Allocation Factor - E1ALL
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] Provided by Duke Energy Progress - Asset Accounting
[8] NC Retail Allocation Factor - PTDG

Duke Energy Progress, LLC NC-3202
Docket No. E-2, Sub 1219 Rebuttal
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018

Asheville Steam Electric Generating Plant Operating and Maintenance Expenses - For the 12 months ended December 31, 2018

Line No.	Account	2018 Asheville Coal [3]	[2]
1	0500000 - Supervsn and Engrng - Steam Oper	345,452	DPALL
2	0500100 - Fossil Oper Superv&Engineer-Re	6,974	DPALL
3	0501150 - Coal & Other Fuel Handling	131,152	E1ALL
4	0501190 - Sale Of Fly Ash-Expenses	660,436	E1ALL
5	0502082 - Re-emission Chem Exp - Reagent	20,217	E1ALL
6	0502100 - Fossil Steam Exp-Other	994,055	DPALL
7	0505000 - Fossil Steam Exp-Other	(1,005)	DPALL
8	0506000 - Fossil Steam Exp-Other	1,077,141	DPALL
9	0507000 - Steam Power Gen-Op Rents	29	DPALL
10	0510000 - Suprvsn and Engrng-Steam Maint	129,357	E1ALL
11	0510100 - Suprvsn & Engrng-Steam Maint R	15,262	E1ALL
12	0511000 - Maint Of Structures-Steam	1,511,338	E1ALL
13	0512100 - Maint Of Boiler Plant-Other	3,320,486	E1ALL
14	0513100 - Maint Of Electric Plant-Other	744,459	E1ALL
15	0514000 - Maintenance - Misc Steam Plant	1,521,659	E1ALL
16	0514300 - Maintenance - Misc Steam Plant	250	E1ALL
17	0569200 - Maint Of Computer Software	12	DTALL
18	0570100 - Maint Stat Equip-Other- Trans	780	DTALL
19	0588100 - Misc Distribution Exp-Other	1	RB_PLT_O_DI_
20	Sum:	10,478,055 [1]	

[1] Direct Operation and Maintenance expenses provided by Regulated Utility Finance
[2] NC Retail Allocation factor to NC-3201
[3] Excludes O&M accounts recovered through fuel clause: 0501180, 0502030, 0502040, 0502070 and 0502080

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plan
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3203
Rebuttal

Asheville Steam Electric Generating Plant Asset Impacts in Proformas and the Test Year

Line No.	Description	Plant in Service 12/31/2018	Calculated Annual Accrual	Actual 12ME Depr Booked	Difference
1	Impact to Income Statement Line Items				
2	Steam Production Plant	$ 462,659 [1]	$ 15,551 [1]	$ 13,843 [1]	$ 1,708
3	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L2	$ 462,659	$ 15,551	$ 13,843	$ 1,708
4	Impact of Asheville Steam Electric Generating Plant retirement to depreciation expense in NC-0802 (L3				$ 1,708
5					
6			CURRENT	PROPOSED	
7		Plant	Calculated	Calculated	
8		in Service	Annual	Annual	Adjustment
9		12/31/2018	Accrual	Accrual	Amount
10	TOTAL STEAM PRODUCTION PLANT (311-316)	462,659 [1]	15,551 [1]	17,069 [1]	1,519
11	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L10	$ 462,659	$ 15,551	$ 17,069	$ 1,519
12	Impact of retirement of Asheville Steam Electric Generating assets to depreciation expense in NC-2602 (L11)				$ 1,519
13					
14		Actual			
15		Net Change			
16		through		Proposed	Depr.
17		2/29/2020		Rate	Exp
18	Electric Plant in Service - Steam Production Balances	$ (462,659) [2]		3.69% [3]	$ (17,073)
19	Impact of Asheville Steam Electric Generating Plant retirement to depreciation expense in NC-1001 (L18)	$ (462,659)			$ (17,073)
20					
21	Actual Depreciation Expense booked in 2018 for Asheville Steam Electric Generating Plar				$ 13,843 [1]
22					
23	Impact to depreciation and amortization (L4 + L12 + L19 + L21)				$ (3)
24					
25		State - NC	State - SC		Total
26	12/31/2017 System Balances Subject to Property Tax	$ 29,182,104 [4]	$ 26,114,764 [4]		
27	2018 Property Tax Expense Paid	64,633 [4]	$ 36,850 [4]		
28	Average Property Tax Rate (L27 / L26)	0.22148%	0.14111%		
29					
30	Asheville Steam Electric Generating Plant in Service Balance at 12/31/2017	$ 461,159 [2]	$ 461,159 [2]		
31	2017 Percent of Asheville Steam Electric Generating Plant of System Balances Subject to Property Tax (L30 / L26)	1.5803%	1.7659%		
32	2018 Property Tax Expense Paid - Allocated to Asheville Steam Electric Generating Plant (L27 x L31)	$ 1,021	$ 651		$ 1,672
33					
34	12/31/2018 System Balances Subject to Property Tax	$ 30,893,953 [4]	$ 27,668,026 [4]		
35	Annualized Property Tax Expense (L28 x L34	68,425	39,042		
36					
37	Asheville Steam Electric Generating Plant in Service Balance at 12/31/2018	$ 462,659 [2]	$ 462,659 [2]		
38	2018 Percent of Asheville Steam Electric Generating Plant of System Balances Subject to Property Tax(L37 / L34)	1.49757%	1.67218%		
39	Annualized Property Tax Expense - Allocated to Asheville Steam Electric Generating Plant (L35 x L38)	1,025	653		
40					
41	Property Tax Expense Adjustment - Allocated to Asheville Steam Electric Generating Plant (L39 - L32)	$ 3	$ 2		$ 5
42	Impact of Asheville Steam Electric Generating Plant assets to property tax in NC-0901 (L41				$ 5
43					
44	Electric Plant in Service - Steam Production Activity	(462,659) [2]	(462,659) [2]		
45	Impact of Asheville Steam Electric Generating Plant assets to property tax in NC-1001 (L44 * L28	(1,025)	(653)		$ (1,678)
46					
47	Impact to general taxes (L32 + L41 + L45)				$ -

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3203
Rebuttal
Page 2 of 2

Asheville Steam Electric Generating Plant Asset Impacts in Proformas and the Test Year

Line No.	Description	Actual Net Change through 2/29/2020		Actual Balance at 12/31/2018		Adjustment Amount
48	Impact to Rate Base Line Items					
49	Electric Plant in Service - Steam Production Balances	$ (462,659) [2]				$ (462,659)
50	Impact of Asheville Steam Electric Generating Plant retirement to electric plant in service in NC-1002 (L49)	$ (462,659)				$ (462,659)
51						
52	Plant in Service balance for the Asheville Steam Electric Generating Plan			$ 462,659 [2]		$ 462,659
53						
54	Impact to electric plant in service (L50 + L52)					$ -
55						
56	Accumulated Depreciation - Steam Balances	$ 322,527 [2]				$ 322,527
57	Impact of Asheville Steam Electric Generating Plant retirement to accumulated depreciation in NC-1003 (L56)	$ 322,527				$ 322,527
58						
59	Accumulated Depreciation balance for the retired Asheville Steam Electric Generating Plar			$ (322,527) [2]		$ (322,527)
60						
61	Impact to accumulated depreciation (L57 + L59)					$ -
62						
63		Actual Plant		Calculated	Forecasted	
64		in Service	Current	Annual	12ME Depr	
65		2/29/2020	Rate	Accrual	Booked	Difference
66	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L41	$ - [5]	2.99% [6]	$ -	- [2]	$ -
67	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L66	$ -		$ -	$ -	$ -
68	Impact of Asheville Steam Electric Generating Plant retirement to accumulated depreciation in NC-1007 (L67)					$ -
69						
70	Impact to accumulated depreciation (L57 + L59 + L68)					$ -
71						
72	Total net plant (L54 + L70)					$ -

[1] Provided by Duke Energy Progress - Asset Accounting
[2] NC-3204 - Asheville Steam Electric Generating Plant - Balances
[3] Represents proposed new depreciation rates as of December 31, 2018 test period in the DEP depreciation study
[4] NC-0901 - Annualize property taxes on year end plant balance
[5] Actual Plant in Service amounts provided by Duke Energy Progress - Asset Accounting
[6] Calculated current rate based on the Calculated Annual Accrual amount divided by the Plant in Service at 12/31/2018 in Line

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3204
Rebuttal

Asheville Steam Electric Generating Plant - Balances

Line No.	Description	ACTUALS Dec 2017 [1]	Dec 2018 [1]	Feb 2020 [2]	Net Change
1		a	b	c	d = c - b
2	Electric Plant in Service - Balances				
3	Steam Production:				
4	Asheville Steam Electric Generating Plant	$ 461,159	$ 462,659	$ -	$ (462,659)
5	Steam Production Total (Sum L4)	$ 461,159	$ 462,659	$ -	$ (462,659)
6					
7	Balance in Plant in Service related to Asheville Steam Electric Generating Plant retirement (L5)	$ 461,159	$ 462,659	$ -	$ (462,659)
8					
9	Accumulated Depreciation - Balances				
10	Steam Production:				
11	Asheville Steam Electric Generating Plant - Life reserve		$ (314,952)	$ -	$ 314,952
12	Asheville Steam Electric Generating Plant - COR reserve		(7,575)	-	7,575
13	Steam Production Total (Sum L11)		$ (322,527)	$ -	$ 322,527
14					
15	Balance in Accumulated Depreciation related to Asheville Steam Electric Generating Plant retirement (L13)		$ (322,527)	$ -	$ 322,527
16					
17	Depreciation Expense - Forecasted 12 Months Activity as of February 29, 2020				
18	Steam Production:				
19	Asheville Steam Electric Generating Plant (-L11 col. d x 12/14)				$ -
20	Steam Production Total				$ -
21					
22	Depreciation Expense related to Asheville Steam Electric Generating Plant retirement				$ -

[1] Provided by Duke Energy Progress - Asset Accounting
[2] Plant in service and accumulated depreciation related to Asheville Steam Electric Generating plant was retired and reclassified to a regulatory asset in January 2020, with true-up adjustments in February 2020. The impacts of the retirement of Asheville plant are included in actual plant in service data in NC-1000. NC-3200 has been updated to exclude impacts to plant in service and accumulated depreciation balances as a reuslt of the retirement.

Duke Energy Progress, LLC NC-3205
Docket No. E-2, Sub 1219 Rebuttal
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization

Line No.	Description	Total Carolinas	NC Retail Allocation	Total NC Retail
1	Impact to Income Statement Line Items			
2	Projected August 31, 2020 retired Asheville plant regulatory asset balance	$ 121,553 [1]	61.5278% [2]	$ 74,789
3	Years to amortize	7		7
4	Impact to depreciation and amortization (L2 / L3)	$ 16,575		$ 10,198
5				
6	Statutory tax rate	23.1693% [3]		23.1693% [3]
7	Impact to income taxes (-L4 x L6)	$ (3,840)		$ (2,363)
8				
9	Impact to operating income (-L4 - L7)	$ (12,735)		$ (7,836)
10				
11	Impact to Rate Base Line Items			
12	Projected August 31, 2020 retired Asheville plant regulatory asset balance (L2)	$ 121,553		$ 74,789
13	Less: 1st year amortization (-L4)	(16,575)		(10,198)
14	Projected deferral balance for rate base (L12 + L13)	$ 104,977		$64,590
15				
16	Impact to working capital investment (L14)	$ 104,977		$64,590
17				
18	Deferred tax rate	23.1693% [3]		23.1693% [3]
19	Impact to accumulated deferred income tax (-L16 x L18)	$ (24,323)		$ (14,965)
20				
21	Impact to rate base (L16 + L19)	80,655		49,625

[1] NC-3206 - Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization Schedule at 8/31/2020, Line 7
[2] NC Retail Allocation Factor - DPALL
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10.

Duke Energy Progress, LLC NC-3206
Docket No. E-2, Sub 1219 Rebuttal
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018
(Dollars in thousands)

Retired Asheville Steam Electric Generating Plant Regulatory Asset Amortization Schedule

Line No.		Beginning Balance	Monthly Amortization Expense	Ending Balance
1	2/1/2020	$ 132,701 [1]	$ (1,593) [2]	$ 131,109
2	3/1/2020	131,109	(1,593)	129,516
3	4/1/2020	129,516	(1,593)	127,923
4	5/1/2020	127,923	(1,593)	126,331
5	6/1/2020	126,331	(1,593)	124,738
6	7/1/2020	124,738	(1,593)	123,146
7	8/1/2020	123,146	(1,593)	121,553

[1] NC-3207, Line 6
[2] NC-3207, Line 15

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Reflect retirement of Asheville Steam Electric Generating Plant
For the test period ended December 31, 2018

NC-3207
Rebuttal

Retired Asheville Steam Electric Generating Plant Regulatory Asset Schedule and Amortization Calculation

Line No.	Description	Total	
1	Calculation of Net Book Value of retired Asheville Steam Electric Generating Plant		
2	Electric Plant in Service balance	$ 457,660,037	[1]
3	Accumulated Depreciation balance	(328,501,436)	[1]
4	Materials and Supplies Inventory	11,008,080	[1]
5	COR Reserve balance	(7,465,272)	[1]
6	Net Book Value of Asheville Steam Electric Generating Plant at retirement, 01/31/2019 (L2 + L3 + L4 + L5)	$ 132,701,409	[4]
7			
8	Calculation of monthly amortization of Asheville Steam Electric Generating Plant at retirement, 01/31/2020		
9	Life Net Book Value to be recovered (L2 + L3 + L4)	$ 140,166,680	
10	Remaining COR to be recovered after retirement of plant	11,134,728	[2]
11	Total to be recovered for Asheville Steam Electric Generating Plant at end of amortization period (L9 + L10)	$ 151,301,409	
12			
13	Monthly Amortization expense, Life Net Book Value (L9 /95 months)	$ (1,475,439)	[3]
14	Monthly Amortization expense, COR (L10 /95 months)	(117,208)	[3]
15	Total monthly amortization expense	$ (1,592,646)	

[1] Provided by Duke Energy Progress Asset Accounting - estimated net book value of Asheville Steam Electric Generating plant after retirement date in January 2020. Includes true-up adjustments as of 02/29/2020 (excludes Land and General plant)

[2] Represents the most recent dismantlement study estimate of $18.6 million, less the COR Reserve balance at the date of retirement, Line 5.
[3] Monthly amortization begin date February 1, 2020 through original retirement date December 31, 2027 = 95 months
[4] Duke Energy Progress Asset Accounting expects additional entries to impact retirement finalization in February 2020. An update will be provided in the February 2020 supplemental filing.

Duke Energy Progress, LLC NC-3400
Docket No. E-2, Sub 1219 Rebuttal
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

Detailed Narrative Explanation of Adjustment

This pro forma adjusts depreciation expense and income taxes for the amortization of deferred costs related to Asheville Combined Cycle. The Company is seeking a deferral of depreciation, property taxes, incremental O&M and return associated with the Asheville Combined Cycle from the date the plant is estimated to go into operation, December 2019, until rates are effective in September 2020.

The impact to operating income was determined as follows:

The impact to depreciation expense reflects an annual level of amortization of deferred costs related to Asheville Combined Cycle, including a return on investment. Deferred costs are being amortized over a three year period.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

The impact to rate base was determined as follows:

The impact to working capital is determined by including the regulatory asset balance in rate base and offsetting it with one year of amortization. In addition, the asset is offset by associated ADIT.

December Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through December 2019.

Updated NC-3405 for the estimated amount to go in service through February 2020.

January Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through January 2019.

Updated NC-3405 for the estimated amount to go in service through February 2020.

February Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through February 2020; updated NC-3402 and NC-3403 to exclude O&M from Asheville CC deferral; NC-3406 updated to include the actual level of inventory on hand at Asheville CC when it became operational (01/31/2020)

Rebuttal

Updated NC-3406 after discussions with PS on O&M annualization methodology for new plant.

Updated NC-3403 for new Asheville EPIS and associated ADIT for March and April 2020. Asheville CC Unit 8 went into service on April 5, 2020, not March 2020.

Updated NC-3405 for Other Production Plant in service balance for Asheville Unit 8 costs in service April 5, 2020.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3400
Rebuttal

Line No.	Description	Source	Total NC Retail Rebuttal	February	Application	Change
1			Rebuttal	February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue		$ -	$ -	$ -	$ -
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation		-	-	-	-
9	Purchased power		-	-	-	-
10	Other operation and maintenance expense	NC-3401	2,613	6,109	6,109	(3,496)
11	Depreciation and amortization	NC-3401	10,493	11,576	13,594	(3,101)
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes	NC-3401	(3,037)	(4,098)	(4,565)	1,529
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	10,069	13,588	15,138	(5,069)
18						
19	Operating income	L4 - L17	$ (10,069)	$ (13,588)	$ (15,138)	$ 5,069
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					
24						
25						
26	**Pro Formas Impacting Rate Base Line Items**					
27						
28	Electric plant in service		$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-
31						
32	Add:					
33	Materials and supplies	NC-3401	3,488	3,488	3,735	(248)
34	Working capital investment	NC-3401	20,986	23,151	27,188	(6,202)
35						
36						
37	Less:					
38	Accumulated deferred taxes	NC-3401	(4,862)	(5,364)	(6,299)	1,437
39	Operating reserves		-	-	-	-
40						
41						
42	Construction work in progress		-	-	-	-
43						
44	Total impact to rate base	Sum L30 through L42	$ 19,611	$ 21,275	$ 24,624	$ (5,013)
45						
46	Note:					
47	Rate Base: positive number increases rate base / negative number decreases rate base					

Duke Energy Progress, LLC NC-3401
Docket No. E-2, Sub 1219 Rebuttal
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description		Total NC Retail	
1	Impact to Income Statement Line Items			
2	Average Annual Combined Cycle O&M	$	2,613	[1]
3	Impact to O&M (L2)	$	2,613	
4				
5	Balance for amortization	$	31,479	[2]
6	Years to amortize		3	
7	Impact to depreciation and amortization (L5 / L6)	$	10,493	
8				
9	Statutory tax rate		23.1693%	[3]
10	Impact to income taxes (-(L3+ L7) x L9)	$	(3,037)	
11				
12	Impact to operating income (-L3 - L7 -L10)	$	(10,069)	
13				
14				
15	Impact to Rate Base Line Items			
16	Estimated level of inventory at Asheville CC at operational date	$	3,488	[1]
17	Impact to materials and supplies (L16)	$	3,488	
18				
19	Regulatory asset at Sep 1, 2020 (L5)	$	31,479	
20	Less first year of amortization (-L7)		(10,493)	
21	Impact to working capital investment (Sum L19 through L20)	$	20,986	
22				
23	Deferred tax rate		23.1693%	[3]
24	Impact to accumulated deferred income tax (-L21 x L23)	$	(4,862)	
25				
26	Impact to rate base (L17 + L21 + L24)	$	19,611	

[1] NC-3406 Asheville Combined Cycle - Average O&M and Inventory Balances
[2] NC-3402 Expected Balance of Deferred Costs at September 1, 2020 - Asheville Combined Cycle (NC Retail)
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC NC-3402
Docket No. E-2, Sub 1219 Rebuttal
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Expected Balance of Deferred Costs at September 1, 2020 - Asheville Combined Cycle - NC Retail

Line No.	Description	Other Production [1]	Transmission [2]	Total NC Retail	
1	Deferred Cost of Capital	$ 16,335	$ 475	$ 16,809	[1]
2	Deferred Depreciation	11,062	94	11,156	[1]
3	Deferred O&M Expense	1,770	-	1,770	[1]
4	Deferred Property Tax Expense	1,040	20	1,060	[1]
5	After-Tax Return on Deferred Expenses	668	16	684	[1]
6	Total expected deferral balance in Regulatory Asset (Sum L1 through L5)	$ 30,874	$ 605	$ 31,479	

[1] NC-3403 - Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail, Line 13

[2] NC-3404 - Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail, Line 13

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail

Line No.	Description	Plant Bal [1]	ADIT Bal [2]	Average Inventory Bal [3]	Accumulated Depreciation	Remove CWIP in Rate Base [4]	Rate Base		Deferred Cost of Capital 2019	Deferred Cost of Capital 2020	Deferred Cost of Capital Total	Deferred Depreciation 2019	Deferred Depreciation 2020	Deferred Depreciation Total	Deferred O&M Expense [5] 2019	Deferred O&M Expense [5] 2020	Deferred O&M Expense [5] Total
1																	
2	Plant in Service Dec 2019 costs (U1 12/27/19)	302,260	(28,013)	3,488	-	(102,930)	174,805		162		162	-		-	28		28
3	Jan 2020 costs	347,271	(32,184)	3,488	(1,035)	(102,930)	214,610			1,546	1,546		1,035	1,035		218	218
4	Feb 2020 costs	347,271	(32,184)	3,488	(2,223)	(102,930)	213,421			1,537	1,537		1,189	1,189		218	218
5	Mar 2020 costs	347,271	(32,184)	3,488	(3,412)	(102,930)	212,233			1,529	1,529		1,189	1,189		218	218
6	Apr 2020 costs	471,960	(43,740)	3,488	(4,600)	(102,930)	324,177			2,335	2,335		1,189	1,189		218	218
7	May 2020 costs	471,960	(43,740)	3,488	(6,216)	(102,930)	322,561			2,324	2,324		1,615	1,615		218	218
8	Jun 2020 costs	471,960	(43,740)	3,488	(7,831)	(102,930)	320,946			2,312	2,312		1,615	1,615		218	218
9	Jul 2020 costs	471,960	(43,740)	3,488	(9,446)	(102,930)	319,331			2,300	2,300		1,615	1,615		218	218
10	Aug 2020 costs	471,960	(43,740)	3,488	(11,062)	(102,930)	317,715			2,289	2,289		1,615	1,615		218	218
11																	
12	Total Costs Through Aug 31,2020								162	16,172	16,335	-	11,062	11,062	28	1,742	1,770
13																	
14								After-Tax	Tax		Pre-Tax						
15	Cost of Capital [8]:							Equity	Rate		Equity						
16	Assumed Capital Structure:																
17	Long-Term Debt							48.00%									
18	Common Equity							52.00%									
19																	
20	Cost Rates:																
21	Long-Term Debt							4.05%			4.0500%						
22	Common Equity							9.90%	23.1693%		12.8855%						
23								13.95%			16.9355%						
24	Cost Components:																
25	Long-Term Debt							1.9440%			1.9440%	22.4884%					
26	Common Equity							5.1480%	23.1693%		6.7004%	77.5116%					
27	Rate							7.0920%			8.6444%	100.0000%					
28																	
29	Depreciation Rates:																
30	Book depreciation rate - Other Production - Asheville CC							4.11%	[10]								
31	Average Property Tax Rate							0.3626%	[9]								
32	Deferred tax rate								23.1693% [7]								

NC-3403
Page 1 of 2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail

Line No.	Description	Deferred Property Tax Expense [6] 2019	Deferred Property Tax Expense [6] 2020	Deferred Property Tax Expense [6] Total	After-Tax Return on Deferred Expenses 2019	After-Tax Return on Deferred Expenses 2020	After-Tax Return on Deferred Expenses Total	Deferred Total 2019	Deferred Total 2020	Deferred Total Total
1										
2	Plant in Service Dec 2019 costs (U1 12/27/	12		12	0		0	202		202
3	Jan 2020 costs		105	105		10	10		2,913	2,913
4	Feb 2020 costs		105	105		27	27		3,076	3,076
5	Mar 2020 costs		105	105		46	46		3,086	3,086
6	Apr 2020 costs		143	143		66	66		3,951	3,951
7	May 2020 costs		143	143		91	91		4,390	4,390
8	Jun 2020 costs		143	143		117	117		4,404	4,404
9	Jul 2020 costs		143	143		143	143		4,419	4,419
10	Aug 2020 costs		143	143		169	169		4,433	4,433
11										
12	Total Costs Through Aug 31,2020	12	1,028	1,040	0	668	668	202	30,672	30,874
13										
14										
15	Cost of Capital [8]:									
16	Assumed Capital Structure:									
17	Long-Term Debt									
18	Common Equity									
19										
20	Cost Rates:									
21	Long-Term Debt									
22	Common Equity									
23										
24	Cost Components:									
25	Long-Term Debt									
26	Common Equity									
27	Rate									
28										
29	Depreciation Rates:									
30	Book depreciation rate - Other Production - Asheville CC									
31	Average Property Tax Rate									
32	Deferred tax rate									

[1] NC-3405 - Asheville Combined Cycle - Plant in Service - Costs by Month
[2] Other Production additions that qualify for bonus depreciation multiplied by 40% and then the deferred tax rate on Line 32
[3] NC-3406 - Asheville Combined Cycle - Average O&M and Inventory Balances, Line 13
[4] NC-1011 - Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142
[5] O&M during the deferral period was removed from the calculation for February supplemental filing.
[6] Plant Balance column divided by 12 months multiplied by Line 31.
[7] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[8] Cost of capital rates from Docket No. E-2, Sub 1142
[9] NC-0901 - Annualize property taxes on year end plant balances - Average property tax rate-Combined NC and SC
[10] Asheville CC composite depreciation rate provided by Asset Accounting
[11] Adjusted to reflect a rates effective date of Sep 1, 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail

Line No.	Description	Plant Bal [1]	ADIT Bal [2]	Average Inventory Bal [3]	Accumulated Depreciation	Remove CWIP in Rate Base	Rate Base		Deferred Cost of Capital 2019	Deferred Cost of Capital 2020	Deferred Cost of Capital Total	Deferred Depreciation 2019	Deferred Depreciation 2020	Deferred Depreciation Total	Deferred O&M Expense [4] 2019	Deferred O&M Expense [4] 2020	Deferred O&M Expense [4] Total
1																	
2	Plant in Service Dec 2019 costs	7,422	(67)	-	-	-	7,354		53		53			-	-		-
3	Jan 2020 costs	7,431	(67)	-	(12)	-	7,351			53	53		12	12		-	-
4	Feb 2020 costs	7,436	(67)	-	(24)	-	7,345			53	53		12	12		-	-
5	Mar 2020 costs	7,436	(67)	-	(35)	-	7,333			53	53		12	12		-	-
6	Apr 2020 costs	7,436	(67)	-	(47)	-	7,322			53	53		12	12		-	-
7	May 2020 costs	7,436	(67)	-	(59)	-	7,310			53	53		12	12		-	-
8	Jun 2020 costs	7,436	(67)	-	(71)	-	7,298			53	53		12	12		-	-
9	Jul 2020 costs	7,436	(67)	-	(82)	-	7,286			52	52		12	12		-	-
10	Aug 2020 costs	7,436	(67)	-	(94)	-	7,275			52	52		12	12		-	-
11																	
12	Total Costs Through Aug 31,2020								53	422	475	-	94	94	-	-	-
13																	
14								After-Tax	Tax		Pre-Tax						
15	Cost of Capital [7]:							Equity	Rate		Equity						
16	Assumed Capital Structure:																
17	Long-Term Debt							48.00%									
18	Common Equity							52.00%									
19																	
20	Cost Rates:																
21	Long-Term Debt							4.05%			4.0500%						
22	Common Equity							9.90%	23.1693%		12.8855%						
23								13.95%			16.9355%						
24	Cost Components:																
25	Long-Term Debt							1.9440%			1.9440%	22.4884%					
26	Common Equity							5.1480%	23.1693%		6.7004%	77.5116%					
27	Rate							7.0920%			8.6444%	100.0000%					
28																	
29	Depreciation Rates:																
30	Book depreciation rate - Transmission							1.90%	[9]								
31	Average Property Tax Rate							0.3626%	[8]								
32	Deferred tax rate								23.1693% [6]								

NC-3404
Page 1 of 2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3404
Rebuttal

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail

Line No.	Description	Deferred Property Tax Expense [5] 2019	2020	Total	After-Tax Return on Deferred Expenses 2019	2020	Total	Deferred Total 2019	2020	Total
1										
2	Plant in Service Dec 2019 costs	2		2	0		0	55		55
3	Jan 2020 costs		2	2		1	1		67	67
4	Feb 2020 costs		2	2		1	1		68	68
5	Mar 2020 costs		2	2		1	1		68	68
6	Apr 2020 costs		2	2		2	2		68	68
7	May 2020 costs		2	2		2	2		69	69
8	Jun 2020 costs		2	2		3	3		69	69
9	Jul 2020 costs		2	2		3	3		69	69
10	Aug 2020 costs		2	2		3	3		70	70
11										
12	Total Costs Through Aug 31,2020	2	18	20	0	15	16	55	549	605
13										
14										
15	Cost of Capital [7]:									
16	Assumed Capital Structure:									
17	Long-Term Debt									
18	Common Equity									
19										
20	Cost Rates:									
21	Long-Term Debt									
22	Common Equity									
23										
24	Cost Components:									
25	Long-Term Debt									
26	Common Equity									
27	Rate									
28										
29	Depreciation Rates:									
30	Book depreciation rate - Transmission									
31	Average Property Tax Rate									
32	Deferred tax rate									

[1] NC-3405 - Asheville Combined Cycle - Plant in Service - Costs by Month
[2] Transmission additions that qualify for bonus depreciation multiplied by 40% and then the deferred tax rate on Line 32
[3] Not estimating incremental inventory for the transmission additions.
[4] Not estimating incremental O&M for the transmission additions.
[5] Plant Balance column divided by 12 months multiplied by Line 31.
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] Cost of capital rates from Docket No. E-2, Sub 1142
[8] NC-0901 - Annualize property taxes on year end plant balances - Average property tax rate-Combined NC and SC
[9] NC-0802 - Adjustment of Depreciation Expense to Reflect Plant in Service for 12 Months Ended December 31, 2018, Transmission Other depr rate
[10] Adjusted to reflect a rates effective date of Sep 1, 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3405
Rebuttal

Asheville Combined Cycle - Plant in Service - Costs by Month

Line No.	Year	Month	System Other Production		System Transmission		NC Retail Allocation		NC Retail Allocation		NC Retail Other Production	NC Retail Transmission
1												
2	2019	12	491,258	[1]	12,438	[1]	61.5278%	[2]	59.6699%	[3]	302,260	7,422
3	2020	1	564,413	[1]	12,453	[1]	61.5278%	[2]	59.6699%	[3]	347,271	7,431
4	2020	2	564,413	[1]	12,462	[1]	61.5278%	[2]	59.6699%	[3]	347,271	7,436
5	2020	3	564,413	[1]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	347,271	7,436
6	2020	4	767,067	[4][5]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
7	2020	5	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
8	2020	6	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
9	2020	7	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
10	2020	8	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
11	Total Project Cost		$ 767,067		$ 12,462						$ 471,960	$ 7,436

[1] Estimated amounts provided by Asheville Combined Cycle Project Management
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - DTALL
[4] Forecasted amount updated as of rebuttal is based on actual amounts in service through February, 2020 and the plant impacts of $202,654,000 closed to plant in service in April 2020 after Unit 8 was placed in operation on April 5, 2020.

[5] Adjusted the Asheville CC project costs to exclude approximately $208,000 of Task Force consulting expenses noted in PS DR 125-5

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

NC-3406
Rebuttal

Asheville Combined Cycle - Average O&M and Inventory Balances

Line No.	Account	2017 HF Lee CC	2018 HF Lee CC	2019 HF Lee CC	2017 Sutton CC	2018 Sutton CC	2019 Sutton CC	2019 WS Lee CC	Total	Asheville CC Estimated O&M [1]	NC Retail Allocation		Total NC Retail
1	0546000 - Suprvsn and Enginring - Ct Oper	$ 92,198	$ 100,617	$ 100,007	$ 232,804	$ 179,490	$ 110,939	$ 457,215	$ 1,273,270	$ 141,527	61.5278%	[2]	$ 87,078
2	0548100 - Generation Expenses - Other Ct	119,879	116,758	132,531	148,997	153,474	173,147	61,930	906,716	100,783	61.5278%	[2]	62,010
3	0548200 - Prime Movers - Generators - Ct	65,911	99,916	10,918	502	11,945	(5,327)	103,633	287,498	31,956	61.5278%	[2]	19,662
4	0549000 - Misc - Power Generation Expense	1,381,785	1,743,750	1,317,717	1,315,850	1,015,091	886,985	1,937,135	9,598,313	1,066,872	61.5278%	[2]	656,423
5	0551000 - Suprvsn and Enginring - Ct Maint	177,498	184,128	116,985	230,797	165,793	132,238	180,865	1,188,304	132,082	61.1093%	[3]	80,715
6	0552000 - Maintenance of Structures - Ct	1,547,782	906,408	1,376,132	935,485	1,046,433	1,044,128	1,586,405	8,442,773	938,431	61.1093%	[3]	573,469
7	0553000 - Maint - Gentg and Elect Equip - Ct	1,388,188	1,451,269	1,728,401	1,075,199	888,315	1,130,820	2,184,052	9,846,244	1,094,430	61.1093%	[3]	668,799
8	0554000 - Misc Power Generation Plant - Ct	713,674	917,999	566,782	861,489	845,555	1,080,399	1,850,331	6,836,229	759,861	61.1093%	[3]	464,346
9	0570100 - Maint Stat Equip - Other_Trans	-	1,136	-	-	-	-	5,860	6,996	778	59.6699%	[4]	464
10	Total O&M	$ 5,486,914	$ 5,521,982	$ 5,349,473	$ 4,801,124	$ 4,306,096	$ 4,553,328	$ 8,367,427	$ 38,386,344	$ 4,266,720			$ 2,612,965
11													
12	MW Capacity (Per Duke Energy website)	920	920	920	625	625	625	750		588			
13													
14	Dollars per MW Capacity	$5,964	$6,002	$5,815	$7,682	$6,890	$7,285	$11,157		$4,266,720			
15	Average per MW capacity							$7,256					
16													
17													
18	Actual level of inventory for Asheville CC at the time the plant becomes operational (01/31/2020)									$5,135,089 [5]	67.9178%	[6]	$ 3,487,639

[1] Direct Operation and Maintenance expenses, excluding outage costs, provided by Regulated Utility Finance
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - E1ALL
[4] NC Retail Allocation Factor - DTALL
[5] Estimated Inventory level provided by Supply Chain/Asset Accounting
[6] NC Retail Allocation Factor - PTDG
[7] Per www.duke-energy.com

I/A

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 2
Rebuttal

Line No.	Description	NC RETAIL		Reference
1	Additional base revenue requirement	$	544,262	Smith Rebuttal Exhibit 1
2	REVISED Annual EDIT Rider 1		7,381	Smith Exhibit 3*
3	Annual EDIT Rider 2 - Year 1 giveback		(126,119)	Smith Rebuttal Exhibit 4
4	Regulatory Asset and Liability Rider		(2,091)	Smith Exhibit 5*
5	Subtotal		(120,829)	Sum L3 - L17
6	Net Revenue Increase	$	423,433	

*Note: Refers to Direct Testimony Exhibits

I/A

DUKE ENERGY PROGRESS, LLC
Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 3
Rebuttal

Line No.		Item	Amount
1	Revenue requirement increase per Company application		**585,961**
2	Revenue impact of Company supplemental adjustments		(51,617)
3	Revenue requirement increase per Company Supplemental Filing		**$ 534,344**
4			
5	Revenue impact of Adjustments		
6	Exhibit 1	Change in debt cost rate from 4.155% to 4.110%	(2,855)
7	NC-0200	Update fuel costs to proposed rate	(13)
8	NC-1000	Adjust for post test year additions to plant in service	2,473
9	NC-1200	Annualize O&M non-labor expenses	2,922
10	NC-2200	Synchronize interest expense with end of period rate base	630
11	NC-2300	Adjust cash working capital	(8)
12	NC-2500	Adjust for credit card fees	(38)
13	NC-3200	Reflect retirement of Asheville Steam Generating Plant	11,537
14	NC-3400	Amortize deferred balance Asheville Combined Cycle	(4,730)
15	Total Revenue impact of adjustments		$ 9,918
16			
17	Revenue Requirement per Smith Rebuttal Exhibit 1		**$ 544,262**

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4 - Supplemental
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

			Federal EDIT - Protected NC Retail	Federal EDIT - Unprotected, PP&E related NC Retail	Federal EDIT - Unprotected, non PP&E related NC Retail	NC EDIT NC Retail	Deferred Revenue NC Retail	Total NC Retail
			(A)	(B)	(C)	(D)	(E)	(F)
1	Regulatory Federal EDIT liabilIty including gross up on the books as of 12/31/2018, based on 2017 tax returns	[1]	$ (854,917)	$ (326,704)	$ 4,862	$ (23,726)		(1,200,485)
2	Adjustment to implement ASU 2018-02	[1]			$ (34)	$ -		(34)
2a	Adjustment for Amended 2017 Federal Return	[1]		$ (415)				(415)
3	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2018-12/31/2018	[1]	$ 30,548		$ (30,548)	$ -		-
4	Regulatory Federal EDIT liability including gross up as of 12/31/2018, adjusted for the implementation of ASU 2018-02	[1]	$ (824,369)	$ (327,119)	$ (25,719)	$ (23,726)	$ -	(1,200,934)
5	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2019-8/31/2020	[1]	$ 50,913		$ (50,913)	$ -		-
6	Deferred revenues related to 2017 Federal Tax Rate Change as of 12/31/2018	[1]					$(108,392)	(108,392)
7	Other projected updates through 2/29/2020	[2]				$ (271)	$ (1,923)	(2,194)
8	Regulatory liabilIty for federal tax change including gross up for NC Retail, for Year 1 rider calculation (Sum of L4 to L7)		$ (773,457)	$ (327,119)	$ (76,631)	$ (23,998)	$(110,315)	(1,311,519)
9	Annual Amortization percentage		3.57%	5.00%	20.00%	20.00%	50.00%	9.32%
10	Liability for Annual amortization amount (Col A: L1 , Col B to E: L8)		$ (854,917)	$ (327,119)	$ (76,631)	$ (23,998)	$ (110,315)	(1,392,980)
11	Annual amortization amount (L9 x L10)	[3]	(30,548)	(16,356)	(15,326)	(4,800)	(55,157)	(122,187)
12	Years of rider amortization		27.99	20	5	5	2	11

[1] Excess deferred tax liability (EDIT) as of 12/31/2018 by jurisdiction, and forecast transition to new rates effective date between categories based on Tax analysis of ADIT.
Federal EDIT related to the federal tax changes booked to the 0254036 and 0254038 accounts is included in other Working Capital in the per books cost of service.
NC EDIT related to the NC state tax reduction deferred to the 0254150 account not included for recovery in NC EDIT rider approved in prior DEP NC rate case.
This NC EDIT is included in other Working Capital in the per books cost of service.
Revenues deferred for federal tax changes with accrued returns in the 0229010 account, are currently excluded from rate base in the per books COSS.

[2] Projected updates to the Federal and NC tax EDIT during 2019 by Tax
Smith Exhibit 4 - Supplemental, Page 3, Line 1 return accruals on deferred revenues in the 0229010 account projected through 2/29/2020.

[2a] Updates per Tax

[3] Annual amortization for Federal EDIT-Protected from Tax department, estimated based on ARAM method

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4 - Supplemental
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Smith Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	47.00%	4.11%	1.48%
Equity	53.00%	10.30%	5.46%
			6.94%
Statutory Tax Rate			23.17%
Retention factor for NCUC Fee, Uncollectibles			99.63%

Annual Rider Calculation

Year		Beginning Balance, Page 1, L8 (A)	Federal EDIT - Protected (B)	Federal EDIT - Unprotected, PP&E related (C)	Federal EDIT - Unprotected, non PP&E related (D)	NC EDIT (E)	Deferred Revenue (F)	Total Amortization (G) =(B)+(C)+(D)+[E]+[F]	Ending Balance before Return (H) = (A) - (G)	Average of Beginning and Ending Balance (I) = ((A) + (H)) /2	EDIT Balance in Base Rates, Page 1, L1 (J)	Change in Regulatory Liability for Rider Return (K) = (I) - (J)	Return for Rider (L) = (K) x After Tax WACC	Rider Revenues (M) = (G) + (L)	Rider Revenues NCUC Fee, Uncollectibles (N) = (M) / Retention Factor
			Amortization - From Page 1, L11												
Sep 20- Nov 21	1	(1,311,519)	(30,548)	(16,356)	(15,326)	(4,800)	(55,157)	(122,187)	(1,189,333)	($1,250,426)	(1,200,485)	($49,941)	($3,467)	(125,654)	(126,119)
Dec 21- Nov 22	2	(1,189,333)	(30,548)	(16,356)	(15,326)	(4,800)	(55,157)	(122,187)	(1,067,146)	($1,128,239)	(1,200,485)	$72,246	$5,015	(117,171)	(117,605) [1]
Dec 22- Nov 23	3	(1,067,146)	(30,548)	(16,356)	(15,326)	(4,800)	-	(67,029)	(1,000,117)	($1,033,631)	(1,200,485)	$166,854	$11,583	(55,446)	(55,651) [1]
Dec 23- Nov 24	4	(1,000,117)	(30,548)	(16,356)	(15,326)	(4,800)	-	(67,029)	(933,087)	($966,602)	(1,200,485)	$233,883	$16,237	(50,793)	(50,981) [1]
Dec 24- Nov 25	5	(933,087)	(30,548)	(16,356)	(15,326)	(4,800)	-	(67,029)	(866,058)	($899,572)	(1,200,485)	$300,913	$20,890	(46,139)	(46,310) [1]

Initially Filed, Year 1 Rider Revenue ($127,633)
1,514

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by September 30th for Commission approv

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4 - Supplemental
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL

	Deferred Revenue for Federal Tax Rate Change in account 0229010	NC Retail
1	Projected Changes in Deferred Revenue for Federal Tax Rate Change through Feb 2020	($1,923,073)

Nos. 271A18 & 401A18

SUPREME COURT OF NORTH CAROLINA

****

<table>
<tr><td>STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION; DUKE ENERGY PROGRESS, LLC, Applicant,

Appellees,

v.

ATTORNEY GENERAL JOSHUA H. STEIN, Intervenor; SIERRA CLUB, Intervenor,

Appellants,

PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION, Intervenor,

Cross-Appellant.</td><td>)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)</td><td><u>From the North Carolina Utilities Commission</u>

<u>Docket No. E-2, Sub 1142</u></td></tr>
</table>

and

SUPREME COURT OF NORTH CAROLINA

****

STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION; DUKE ENERGY CAROLINAS, LLC, Applicant,	)	
Appellees,	)	
v.	)	
ATTORNEY GENERAL JOSHUA H. STEIN, Intervenor; SIERRA CLUB, Intervenor; NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, Intervenor; NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL, and SOUTHERN ALLIANCE FOR CLEAN ENERGY, Intervenors,	)	From the North Carolina Utilities Commission Docket No. E-7, Sub 1146
Appellants,	)	
PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION, Intervenor,	)	
Cross-Appellant.	)	

****

JOINT BRIEF OF APPELLEES DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

****

INDEX

TABLE OF CASES AND AUTHORITIES

Page(s)

Cases

Statutes

Session Laws

Code of Federal Regulations

Federal Register

Other Authorities

North Carolina Utilities Commission Orders

Nos. 271A18 & 401A18

SUPREME COURT OF NORTH CAROLINA

****

STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION; DUKE ENERGY PROGRESS, LLC, Applicant,	)	
Appellees,	)	
v.	)	
ATTORNEY GENERAL JOSHUA H. STEIN, Intervenor; SIERRA CLUB, Intervenor,	)	From the North Carolina Utilities Commission
	)	Docket No. E-2, Sub 1142
Appellants,	)	
PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION, Intervenor,	)	
Cross-Appellant.	)	

and

SUPREME COURT OF NORTH CAROLINA

****

STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION; DUKE ENERGY CAROLINAS, LLC, Applicant,	)	
Appellees,	)	
v.	)	
ATTORNEY GENERAL JOSHUA H. STEIN, Intervenor; SIERRA CLUB, Intervenor; NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, Intervenor; NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL, and SOUTHERN ALLIANCE FOR CLEAN ENERGY, Intervenors,	)	From the North Carolina Utilities Commission Docket No. E-7, Sub 1146
Appellants,	)	
PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION, Intervenor,	)	
Cross-Appellant.	)	

****

JOINT BRIEF OF APPELLEES DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

****

INTRODUCTION

North Carolina's Public Utility Act sets out a formula and process for determining the retail rates to be charged by electrical utilities, such as Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively "Duke Energy" or "Company"). N.C. Gen. Stat. § 62-133. Under the Act, the responsibility for regulating rates lies with the North Carolina Utilities Commission (the "Commission" or the "Utilities Commission"). *Utilities Comm'n v. Thornburg*, 316 N.C. 238, 242, 342 S.E.2d 28, 31 (1986) ("The Commission, not the courts, has been given the authority to regulate the rates of public utilities.").

This Court gives deference to the expertise of the Utilities Commission "as to the credibility and import of the evidence presented." *Utilities Comm'n v. Mebane Home Tel. Co.*, 35 N.C. App. 588, 594, 242 S.E.2d 165, 168 (1978); *accord Utilities Comm'n v. Carolina Utility Customers Ass'n*, 323 N.C. 238, 243, 372 S.E.2d 692, 695 (1988) (noting that this Court gives "great deference" to the Commission when it is exercising its discretion in setting rates). A decision of the Commission should only be reversed if the Commission violated the Constitution, exceeded its statutory authority, acted arbitrary or capriciously, engaged in unlawful proceedings, made errors of law or made findings that are not supported by competent and substantial evidence. N.C. Gen. Stat. § 62-94(b). The General Assembly has afforded the decisions of the Commission great deference as a result of the Commission's expertise and in order to ensure consistency in rates over time – thus protecting consumers from short-term rate reductions that increase the utility's borrowing costs and consequently result in higher utility rates in the long term. *See Thornburg*, 316 N.C. at 242, 342 S.E.2d at 31.

The rate formula that the General Assembly has mandated is: 1) the reasonable original cost of the utility's property (less depreciation) used and useful[1] in providing services, multiplied by 2) a fair rate of return; plus 3) the utility's reasonable operating expenses. N.C. Gen. Stat. § 62-133. As of December 31, 2016, Duke Energy's North Carolina retail rate base (without adjustments in connection with this rate case) was $21.9 billion. DEC Doc. Ex. 32 ($13,814,781,000); DEP Doc. Ex. 1406 ($8,102,086,000). A small increase in the cost of capital can increase the utility's capital costs by hundreds of millions of dollars per year.[2] Because the cost of obtaining capital, whether through equity or debt investment, is an element of the rate formula (*see* N.C. Gen. Stat. § 62-133(b)(4)), these costs must be determined in each general rate case.

If the Commission does not set rates at a level that allows the utility to fully recoup its operating costs, its borrowing costs, and its costs of attracting equity investment, then the diminished financial strength of the utility makes it more costly

---

[1] The term "used and useful," while not defined by statute, encompasses that which both (1) serves the public, and (2) is funded by debt and/or equity investors. *See Utilities Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 414-15, 206 S.E.2d 283, 295-96 (1974).

[2] An increase of just one percent in the borrowing rate and rate to attract equity would cost consumers $219 million each year (i.e., one percent of $21.9 billion).

to obtain loans and raise equity. In the 2018 rate case orders here on appeal,[3] the Commission directly confronted these competing interests. (*See*, *e.g.*, DEP R p 676 (setting rates at a level that does not allow a utility to recover all of these costs will cause retail rates to increase in the long term and consequently be harmful to ratepayers)). Moody's Investor Service sets its credit ratings in substantial part based on the regulatory environment (i.e., whether the utilities commission authorizes recovery of operating and investment costs). (DEP T Vol 8, p 167). If Duke Energy were not allowed to recover coal ash basin closure costs, its credit rating would decline, and its cost of capital (which are part of the ratemaking formula) would increase. (*Id.*; *see also* DEP T Vol 8, p 435 ("[I]f the Public Staff's position on coal ash were to be [adopted,] I think you would be looking at a totally new day in the way investors look at [Duke Energy.]")).

Over the last several decades, the Utilities Commission has carefully considered these trade-offs and has applied its expertise to protect the interests of consumers, preserve the financial stability of utilities, and faithfully apply the formula established by the General Assembly. Consequently, retail electrical utility rates in North Carolina are among the lowest in the country, and this has been consistently true for years. (DEC T Vol 4, p 164). This fact is particularly significant given that Duke Energy has incurred substantial costs to install state-of-the-art

---

[3] *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Sub 1146 (the "DEC 2018 Rate Case Order" or the "DEC Order") and *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, Docket No. E-2, Sub 1142 (Feb. 23, 2018) (the "DEP 2018 Rate Case Order" or the "DEP Order").

pollution controls, transition from coal to cleaner burning fuels, and improve transmission infrastructure. (DEC R p 880; DEP R p 557; *see* DEC T Vol 6, p 177). As a result of this costly transition, less than a third of the electricity used in North Carolina comes from coal-fired plants. (DEP T Vol 8, pp 106, 111 n.44; DEC T Vol 4, pp 141, 146 n.44).

As the Commission recognized in its decision, Duke Energy must maintain its credit-worthiness to compete for capital on reasonable terms. (DEC R p 882; DEP R p 559). *See Utilities Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 407, 206 S.E.2d 283, 290-291 (1974) ("It is in the public interest that a public utility company charge for its services rates which will enable it to maintain its financial ability to render adequate service and to attract the capital necessary for expansion and improvement of its service as needed."). If Duke Energy were not permitted to recoup any of the elements set out in the ratemaking formula, the result would be to encourage investors to turn to other investment vehicles. (DEC R p 884; DEP R p 561). When this occurs, "the loss of equity investors would start a chain reaction: utility companies would have to take on more debt, which would drive up their cost of borrowing and, in turn, their rates." H. Mallory Caldwell, *Note: Deconstructing and Reconstructing Consolidated Tax Savings for Public Utilities*, 12 Va. Tax Rev. 735, 764 (1993). In contrast, allowing a utility to recoup its operating, borrowing and opportunity costs "keeps down future borrowing costs by reducing investor risk." J. Gregory Sidak & Daniel F. Spulber, *Deregulatory Takings and Breach of the Regulatory Contract*, 71 N.Y.U.L. Rev. 851, 881 (1996). As noted scholars have explained, when regulators set rates so that investors are unable to recover their cost of capital, "today's customers may gain from this policy, [but] tomorrow's customers are likely to lose." A. Lawrence Kolbe & James Read, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* at 22 (1984). Moreover, as the utility loses the ability to obtain capital at reasonable cost, "customers will have to make do with less efficient equipment (for example, from failure to replace [antiquated] electricity generating stations), and with less capacity and a lower safety margin…." *Id.* at 23.

As one witness explained, Duke Energy's customers "benefit through lower electric rates when the Company has lower financing costs [and] greater access to capital." (DEC T Vol 4, pp 88-89). Deviating from the cost recovery standards mandated by the General Assembly would result in the State's regulated utilities being perceived as riskier by investors and lenders, thereby leading to higher costs of capital. (DEC T Vol 11, pp 176). While the desire to lower utility rates in the short run may be tempting, the Attorney General, Public Staff and other Appellants fail to recognize that the effect of ignoring the formula set by the General Assembly will inevitably be to harm consumers in the long term. (*See* DEC R p 1100 (failing to allow Duke Energy to recoup the time value of money will "ultimately increase[e] the Company's cost of capital")). Increased borrowing costs will also impede Duke Energy's ability to implement cleaner alternative energy sources and to modernize the power grid.

As a result, while lowering electricity rates may appear to benefit consumers in the short run, it will increase the cost of electricity in the long run due to the increased cost of capital. (DEC T Vol 4, p 220) ("a return too low in the near-term may produce higher customer rates in the future"). This Court already observed that while it may seem that shifting recoverable costs to shareholders would benefit ratepayers, it "may actually in the long term be less favorable to the ratepayers." *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 463, 480-81, 385 S.E.2d 451, 461 (1989). What ratepayers may "save" in the short run, "they lose in higher rates of return as well as diminished utility stature in the capital markets." *Id.* (internal quotations omitted). The ability of a utility to obtain capital at favorable rates is an asset to ratepayers that can quickly be lost when a utility is not allowed to recover its costs. (*See* DEC T Vol 4, pp 42-43 (Standard & Poor's has stated that the Company's credit rating will be lowered if it is unable to recover coal ash closure costs)).

Here, the Appellants are advocating that this Court ignore the express provisions of the Public Utilities Act, the expertise of the Commission and the substantial evidence that supports the Commission's factual findings. Their position would harm consumers in the long term and risk destabilizing public utilities in North Carolina. The novel theories advocated by the Appellants should be rejected by this Court.

RESTATEMENT OF THE FACTS

The Commission's findings of fact are conclusive if supported by competent, material and substantial evidence. *State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 336, 189 S.E.2d 705, 717 (1972). While there may well be evidence in the voluminous record in these cases that would support the "facts" as presented by the Appellants, or even their characterization of those facts, the critical inquiry for this Court is whether the facts actually found by the Commission are supported by the Record. Accordingly, the factual recitation set forth in this section of the Brief is drawn directly from the Commission's Orders in these cases. (*See* DEC R pp 1031-1147; DEP R pp 621-685). No party disputes that the facts as actually found by the Commission are supported by "competent, material and substantial evidence"; accordingly, the facts as actually found are "conclusive."

As the Commission found (DEC R pp 1032-33; DEP R pp 621-622):

Coal-fired power plants have played a predominant role in electricity generation by Duke Energy throughout its history, and the Company is still dependent upon coal-fired generation even today. With coal-fired generation comes a by-product – coal ash, also known as coal combustion residuals, or CCRs. At least since the 1950s, standard industry practice, particularly in the Southeastern United States, called for the management of coal ash in coal ash basins, and such basins were constructed and used at all of the Company's coal-fired generating units.

The United States Environmental Protection Agency ("EPA") has studied CCRs and their proper management and handling since the 1980s, but only began moving forward on comprehensive regulation of CCRs less that ten years ago. In

2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule ("CCR Rule") – was promulgated on 17 April 2015. North Carolina also enacted specific statutory requirements for coal ash management in its Coal Ash Management Act ("CAMA"), which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. Duke Energy is, of course, required to comply with these new requirements, which mandate closure of the Company's coal ash basins. Mandated closure triggers Generally Accepted Accounting Principles ("GAAP") provisions (themselves mandatory for publicly traded companies) relating to the retirement of long-lived tangible assets, and specifically triggers the requirement that the Company account for compliance costs through Asset Retirement Obligation ("ARO") accounting. The Company, as required by GAAP, established an ARO with respect to its coal ash basins, and, in accordance with the Commission's orders in Docket No. E-7, Sub 723 (as to DEC) and Docket No. E-2, Sub 826 (as to DEP), deferred the impacts of its GAAP-mandated ARO accounting.

No party opposed the deferral of Duke Energy's actually incurred coal ash basin closure costs. (DEC T Vol 9, p 126). To the contrary, as the Commission held, "Public Staff witness Maness indicated that the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred for regulatory accounting purposes." (DEC R p 1031; *accord* DEP R p 617). The Commission in fact approved the deferred accounting requested by Duke Energy.

(DEC R pp 1031; DEP R pp 620). Approval of deferral has not been challenged by any party in this appeal.

In these cases, Duke Energy sought recovery of the coal ash basin closure costs incurred during specified periods (for each, the applicable "Recovery Period") in connection with CCR Rule and/or CAMA compliance:

- DEC sought recovery of the actual coal ash basin closure costs it incurred from 1 January 2015 through 31 December 2017. On a North Carolina retail jurisdiction basis, these costs amounted to $566.8 million.
- DEP sought recovery of the actual coal ash basin closure costs it incurred from 1 January 2015 through 31 August 2017. On a North Carolina retail jurisdiction basis, these costs amounted to $241.9 million.

Further, in both cases, the applicable Company proposed that, rather than recovering 100% of these already incurred costs immediately, it should recover them over a five-year amortization period, along with a return on the unamortized balance at the applicable Company's weighted average cost of capital, notwithstanding the fact that shareholders and bond holders had provided the funds to pay these costs during the 2015-2017 time frame.

These costs – and *only* these costs – are the costs at issue in these cases. While Appellants seek to call attention to events that they no doubt believe reflect poorly upon Duke Energy, such as the Dan River spill (*see*, *e.g.*, AG Br. p 3) or the

Company's resulting guilty pleas in Clean Water Act proceedings brought by the federal government (*id*.), these events – which the Company acknowledges are serious and for which the Company has taken full responsibility – are not part of the actual cost recovery issues posed in these cases.[4] It is undisputed that costs resulting from the Dan River spill, fines and penalties imposed as a result of the guilty pleas, and any other fines or penalties arising from alleged environmental violations were all excluded from the Company's cost recovery proposal. (DEC R p 1033; DEP R p 622). The Public Staff, the agency required by the Public Utilities Act to audit utility rate requests and recommend adjustments (DEC R p 1142), found no instance in which such costs were included in Duke Energy's cost recovery requests. (DEC R p 1057; DEP R p 642).

As to the actual coal ash basin closure costs incurred by Duke Energy during the applicable Recovery Period, the Commission found that with one minor exception[5] such costs were known and measurable, were reasonable and prudently incurred, and were used and useful in connection with the provision of service to Duke Energy's customers. (DEC R p 1090; DEP R p 667). Based on these findings,

---

[4] Indeed, they are relevant only to the extent that the Commission referred to them in fashioning the management penalty it imposed upon Duke Energy in these cases – $70 million in the case of DEC (DEC R p 1032) and $30 million in the case of DEP (DEP R p 621). No party has appealed from the Commission's imposition of these penalties.

[5] The Commission disallowed $9.5 million of expense from DEP's cost recovery request. (DEP R p 666).

the law requires the recovery of these costs in rates, apart from the management penalty that the Commission imposed and from which no party has appealed.

The Commission further found that the coal ash basin closure costs incurred by Duke Energy during the applicable Recovery Periods were appropriately deferred and appropriately subject to ARO accounting. (DEC R pp 1107-1117; DEP R pp 617-20, 673). As such, these costs "are eligible for deferral and amortization and for earning on the unamortized balance." (DEP R p 675). The Public Staff and its witnesses expressly recognized that the Commission may authorize a rate of return on these deferred costs. (DEC T Vol 22, p 78 ("the Commission can approve a regulatory asset to capture [deferred coal ash closure costs,] and even provide for a return on them due to the deferral of their recovery (by including them in rate base or otherwise providing for carrying costs)"); *Id.* at 137-138 (opinion of Public Staff's Chief Counsel that Commission has discretion to provide for recovery of deferred expenses and to allow a rate of return on this regulatory asset)). Not only is Duke Energy to be afforded recovery of the costs incurred, the Commission acted appropriately in affording the Company a fair rate of return on those costs.

Accordingly, the Commission's Orders should be affirmed in their entirety.

STANDARD OF REVIEW

On appeal, the rates set by the Commission are presumed to be just and reasonable. N.C. Gen. Stat. § 62-94(e). The Commission's findings of fact are conclusive if supported by competent, material and substantial evidence. *State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 336, 189 S.E.2d 705, 717 (1972).

The credibility of witness testimony and the reliability of an expert's opinion are for the Commission to determine, not for this Court. *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 575, 584, 232 S.E.2d 177, 182 (1977). Therefore, the "party attacking rates established by the Commission bears the burden of proving that they are improper." *State ex rel. Utils. Comm'n v. Pub. Staff-N.C. Utils. Comm'n*, 323 N.C. 481, 491, 374 S.E.2d 361, 366 (1988). This Court may only reverse the Commission if the Commission has violated the Constitution, exceeded its statutory authority or jurisdiction, conducted unlawful proceedings, committed an error of law, acted arbitrary or capriciously or if its decision is not supported by substantial evidence. N.C. Gen. Stat. § 62-94(b).

ARGUMENT

There are two basic questions presented in these consolidated appeals. The first implicates basic cost recovery principles: Whether the Commission erred in allowing Duke Energy to recover the coal ash basin closure costs incurred during the applicable Recovery Period, and which the Commission determined were reasonable and prudent (*i.e.*, all such costs save $9.5 million disallowed for DEP) in rates. The answer to this question is "No" – the Commission did not err in its cost recovery determination.

Appellants come at this question from different directions. The Attorney General (and, derivatively through incorporation by reference, Sierra Club) insist that Duke Energy failed to carry its burden of proof to show that the costs incurred were reasonable and prudent. This is addressed in Section I of this Brief. Duke

Energy has demonstrated through analysis of the Commission's actual findings, which are conclusive and supported by substantial evidence, that it did meet its burden; indeed, it exceeded its burden through submission of evidence that the Commission characterized as "compelling." (DEC R p 1110). "Compelling" evidence certainly meets the "substantial evidence" test.

The Public Staff does not contest the Commission's findings that the costs at issue were reasonable and prudent. Rather, it argues that the Commission should have adopted its "equitable sharing" framework so as to share those reasonable and prudent costs between the Company's shareholders and customers. This is addressed in Section IV of this Brief. The central problem with the Public Staff's argument – and one with which it simply ignores – is that by Staff's own admission, "equitable sharing" is discretionary with the Commission. The Commission explicitly declined to exercise this discretion so as to achieve the arbitrary rates outcome desired by Public Staff, and Public Staff has not even attempted to show that the Commission abused the discretion that Public Staff argues the Commission possesses. Further, the Commission correctly expressed doubt as to the lawfulness of the "equitable sharing" approach, finding that it was inherently arbitrary and therefore of questionable legality.

Sierra Club (and only Sierra Club) argues that cost recovery should be denied because Duke Energy allegedly has run afoul of N.C. Gen. Stat. § 62-133.13, which bars electric utilities from recovering in rates the costs related to discharges to surface water – *i.e.*, Dan River-type discharges. This is addressed in Section V. The short answer is that Sierra Club misreads the statute and ignores the complete absence of any link between the coal ash basin closure costs for which recovery was sought in these cases and surface water impairment. No part of the costs incurred were for surface water remediation, and it is undisputed that all costs of the Dan River spill were in fact borne by shareholders.[6]

The second question presented by these consolidated appeals relates to the propriety of a return on the reasonable and prudent costs incurred by Duke Energy: Whether the Commission erred in allowing this return. Here again the answer is "No" – the Commission did not err in authorizing a return on the funds expended by Duke Energy's investors (both debt and equity) and reasonably and prudently incurred in order to comply with coal ash management standards that arose from a change in the law with which the Company had to comply.

Appellants' principal argument is that the coal ash basin closure costs incurred by Duke Energy are properly categorized as "expenses" rather than "property used and useful" in the provision of service to customers, and, therefore, do not merit a return. This is addressed in Sections II and III of this Brief. Appellants impermissibly restrict the plain meaning of the word "property" and completely

---

[6] While it is not completely clear whether he is still making this argument, to the extent that the Attorney General continues to insist that because Duke Energy "caused" CAMA its CAMA-related costs should be disallowed, this issue is addressed in Section VI of this Brief. Intent of legislation enacted by the General Assembly is determined from the text of the legislation itself (which makes no mention whatsoever of any role by Duke Energy in "causing" its enactment), and the "Duke caused CAMA" argument has no bearing on the propriety of cost recovery in these cases.

ignore crucial facts – first, that the costs were deferred, and therefore never in rates prior to the effective date of the rate adjustments ordered in these cases; second, that the costs were accounted for in AROs, and, therefore, appropriately capitalized in accordance with GAAP and FERC rules; and third, that rather than being brought into rates all at once upon the effective date of the rate adjustment, they were a rate mitigation measure amortized over a five-year period. Under these circumstances, the Commission was fully justified and committed no error in authorizing a return on the capital invested by the Company's debt and equity investors to front the coal ash basin closure costs reasonably and prudently incurred during the five-year amortization period over which these costs are being brought into rates.

Accordingly, the DEP and DEC Rate Orders at issue in these appeals should be affirmed.

I. **DUKE ENERGY MET ITS BURDEN TO SHOW THAT COAL ASH BASIN CLOSURE COSTS WERE RECOVERABLE IN RATES**

The first issue presented in the Attorney General's appeal is whether the Commission erred in allowing the coal ash basin closure costs Duke Energy incurred in the applicable Recovery Periods to be recovered in rates. (AG Br. p 2). That, is, the Attorney General challenges the Commission's determination that Duke Energy was entitled to recovery of those costs. The Public Staff does not make this argument. This is a straightforward cost recovery issue. The law governing cost recovery is well established, and the Commission's articulation of the general legal framework (*see* DEC R pp 1081-82) is correct.

A. <u>The General Legal Framework for Recovery of Costs.</u>

A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it in the opening paragraphs to a chapter (titled "The Role of the Revenue Requirement") in their treatise on utility regulation:

> No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit …. Regulated firms are no exception. They face the same constraints ….
>
> A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. … Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

Jonathan A. Lesser & Leonardo R. Giacchino, *Fundamentals of Energy Regulation* 39 (Pub. Utils. Reports, Inc., 1st. ed., 2007) ("Lesser & Giacchino").

Lesser & Giacchino refers to the concept of cost recovery as the "revenue requirement" (*id*.), and the North Carolina Supreme Court has also acknowledged the revenue requirement's central role in utility ratemaking. In *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 484, 490, 385 S.E.2d 463, 466 (1989) (*Thornburg II*) and *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989) (*Thornburg I*), this concept is stated to be embedded in the statutory rate making formula, and, indeed, expressed formulaically:

> This statute [N.C. Gen. Stat. § 62-133] requires the Commission to determine the utility's rate base (RB), its reasonable operating expenses (OE), and a fair rate of return on the company's capital investment

(RR). These three components are then combined according to a formula which can be expressed as follows:

(RB x RR) + OE = REVENUE REQUIREMENT

To be sure, costs are not recoverable simply because they are incurred by the utility. Rather, the utility must show that the costs it seeks to recover are (1) "known and measurable"; (2) "reasonable and prudent"; and (3) in the case of property for which a rate of return is being requested, "used and useful" in the provision of service to customers. N.C. Gen. Stat. § 62-133(b)(1); *Thornburg I*, 325 N.C. 463, 475, 385 S.E.2d 451, 457 (1989). But once it has shown that these metrics are met, the utility is entitled to recover the costs so incurred. *See* N.C. Gen. Stat. § 62-133(b)(5). There is no issue in these appeals with respect to whether the coal ash basin closure costs for which Duke Energy seeks recovery in these cases are "known and measurable"; indeed, Duke Energy exhaustively documented those costs and demonstrated that they were in fact incurred. The "used and useful" concept is more properly associated with a return on costs incurred (or property employed) in connection with service to customers. *See Thornburg I*, 325 N.C. at 475, 385 S.E.2d at 457. Accordingly, the "used and useful" nature of the coal ash basin closure costs incurred by Duke Energy is addressed in Section II, below. Thus, the question of whether the costs at issue here are "reasonable and prudent" is the crux of the Attorney General's challenge to recovery of these costs.

The Commission correctly analyzed the concept of "reasonable and prudent." (DEC R pp 1082-83). It looked to its own precedent and that of this Court to frame the analysis of how to determine whether coal ash basin closure costs incurred by

Duke Energy during the applicable Recovery Period were "reasonable and prudent." In doing so, it relied upon its own decision in *Order Granting Partial Increase in Rates and Charges*, N.C.U.C. Docket No. E-2, Sub 537, 1988 WL 391130, 94 P.U.R.4th 353 (5 August 1988) (the "1988 DEP Rate Order"), in which the Commission's prudence analysis was affirmed by this Court in *Thornburg II*. *See* 325 NC at 489, 385 S.E.2d at 466 (finding "no error" in that portion of the Commission's decision).

The 1988 DEP Rate Case Order's analysis begins with the proper standard for judging prudence: "[W]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. … [T]his standard … must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted." 1988 DEP Rate Order at 368.

Further, challenging prudence requires a detailed and fact-intensive analysis, and the challenger is required to: (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Specifically,

- A decision cannot be imprudent if it represents the only feasible way to accomplish a necessary goal.
- The Commission can only disallow imprudent *expenditures* – that is, actions that are both imprudent and that bear an economic impact on

customers. In turn, actions (even if imprudent) with no economic impact upon customers are of no consequence. Thus, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact.

- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management.

Id.

In these cases, under the prudence framework as articulated by the Commission in the 1988 DEP Rate Case Order and as affirmed by this Court in *Thornburg II*, the Commission determined that the entirety of the coal ash basin closure costs during the applicable Recovery Period were reasonable and prudently incurred, with the exception of $9.5 million in costs incurred by DEP. The Public Staff does not challenge in these appeals the Commission's prudence decision or the prudence framework the Commission articulated.

The Attorney General, on the other hand, does – or at least appears to – challenge the prudence framework as articulated by the Commission. (*See* AG Br. p 62). He argues, incongruously, that the framework is based merely upon a stipulation of the parties in the 1988 DEP Rate Case, as though being based upon a stipulation somehow deprives the framework of any precedential force. His argument is far too limited however, and he utterly ignores critical factors supporting the prudence framework. First, he ignores the fact that, even if originally based upon a stipulation the Commission independently "agreed," that the framework was the "type of approach … required if the prudence standard is to have any meaningful application." 1988 DEP Rate Order at 368. Second, he ignores the fact that this Court found "no error" in the Commission's articulation of the prudence framework. *Thornburg II*, 325 N.C. at 489, 385 S.E.2d at 466.

While seeming to (at least obliquely) challenge the prudence framework, the Attorney General does not actually argue that the Commission's articulation of it is wrong as a matter of law. Nor could he – because it is not wrong. Prudence as a concept is not in the exclusive province of utility regulation. For example, prudence underpins the Business Judgment Rule, "which recognizes that directors often make important decisions under fluid and uncertain circumstances and that a court must be loath to review such judgments on the basis of *ex post* judicial hindsight." *Ehrenhaus v. Baker*, 2008 NCBC 20; 2008 WL 5124899 at *12 (NC Super. Ct. Dec. 5, 2008), *citing Hammonds v. Lumbee River Elec. Mbrshp. Corp.*, 178 N.C. App. 1, 20-22, 631 S.E.2d 1, 13 (2006). So too, the application of the "prudent man" standard in an ordinary negligence case is judged by the circumstances in which the allegedly negligent actor found himself at the time of the incident, not in hindsight. *See*, *e.g.*, *Pintacuda v. Zuckeberg*, 159 N.C. App. 617, 623, 583 S.E.2d 348, 352 (2003) (determining that a negligence analysis "do[es] not judge people's actions based on '20-20 hindsight.' Rather, [it] ask[s] whether a person's actions were reasonable in light of the circumstances at the time of the actions"), *rev'd on other grounds*, 358 N.C. 211, 593 S.E.2d 776 (2004). The prudence standard as articulated by the Commission thus not only was affirmed by this Court in *Thornburg II*, it comports with the manner in which North Carolina appellate courts have analyzed prudence generally.

In summary, the Commission made no error of law in its articulation of the basic cost recovery framework; indeed, its articulation is in full accord with utility regulation generally and the decisions of this Court applying N.C. Gen. Stat. § 62-133 specifically. No party, except the Attorney General, disputes the Commission's articulation and application of the "reasonable and prudent" standard for cost recovery, and this Court should therefore affirm the Commission's articulation and findings.

B. <u>Burden of Proof.</u>

In addition to his implicit challenge to the Commission's application of the "reasonable and prudent" standard discussed above, the Attorney General also attempts to show that Duke Energy failed to carry its ultimate burden of showing that the coal ash basin closure costs it sought to recover were reasonable.

The Attorney General attempts to deny cost recovery by employing the well-established burden of proof framework governing utility ratemaking in general and cost recovery in particular. The Commission itself re-capped this framework:

> The burden of proof to show that rates are just and reasonable is always on the utility. *See* N.C. Gen. Stat. § 62-134(c). But intervenors have a burden of production in the event that they dispute an aspect of the utility's prima facie case. *See, e.g., State ex rel. Utils. Comm'n v. Conservation Council*, 312 N.C. 59, 64 (1984) (utility's costs are "presumed to be reasonable" unless challenged); *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76 (1982) ("The burden of going forward

> with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses….”). If the intervenor meets its burden of production, of course, the ultimate burden of persuasion reverts to the utility, in accordance with N.C. Gen. Stat. § 62-134(c).

(DEC R p 1089).

The Attorney General does not argue that the burden of proof framework articulated by the Commission is in error. Rather, he argues that having put forward some evidence of *past* (*i.e.*, decades-old alleged acts or omissions, occurring long before the applicable Recovery Periods at issue in these cases) imprudence in Duke Energy's handling and management of coal ash, the Attorney General and other Intervenors shifted the burden to Duke Energy to untangle the alleged economic impact caused by such past imprudence upon the current costs, incurred solely within the applicable Recovery Period.

The Attorney General did not and could not allege that the Company had committed any act of imprudence related to the actual costs being sought for recovery in the proceedings below because his own expert witness (Wittliff) made no such determination. Witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. (DEC T Vol 11, pp 282-83). He admitted that he did not identify any specific costs that could have been lower or should be disallowed. (*Id*. at 287-89; DEC R p 1043).

Rather, the Attorney General asserts that Duke Energy failed to retrofit its unlined coal ash ponds by installing liners long before any regulation requiring their installation was promulgated. But this puts Duke Energy in an impossible position. As the Commission noted:

> Had DEC acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEC risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. Had electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan. Even today efforts to soften the impact of the EPA CCR Rule are under consideration by the current administration. If effectuated, anticipated cost recovery may change in the future.

(DEC R p 1137). In the DEP case the Commission made the same finding. (DEP R pp 679-80).

Despite attempting to put Duke Energy into this impossible position, the Attorney General nevertheless insists that the burden of proof shifted to the Company to prove that every action it took or did not take after the time it should have retrofitted in anticipation of unknown future regulation was reasonable. As the Commission put it, the Attorney General argues that Duke Energy "should bear the burden to disprove why disallowances to its … [applicable Recovery Period] CCR remediation costs should not be accepted." (DEC R p 1084). This is a remarkable proposition for which, as the Commission held, the Attorney General "cites no authority." (*Id*.)

In these proceedings, Duke Energy presented evidence, accepted by the Commission, that its actions were reasonable and prudent, its costs incurred were known and measurable, and that the capital provided by investors was used and useful in the provision of service to its customers, and as such the Company was entitled to recover its coal ash basin closure costs incurred during the applicable Recovery Period. Duke Energy's evidence showed that it had managed its coal ash basins in the manner required by applicable regulations and consistent with industry standards prior to the promulgation of the CCR Rule and the enactment of CAMA; that the change in law wrought by the CCR Rule and CAMA caused it to manage coal ash differently, and so it changed its ash handling practices as a result; and that it prudently and at reasonable cost conformed its practices to the new legal requirements. (*See* pp. 28-33, below). The evidence further showed that Duke Energy met the standards for deferral of the costs incurred in the applicable Recovery Period, and that those costs were appropriately accounted for in an ARO. (*See* pp. 45-48 and 48-58, below). The Commission was persuaded by this evidence, and so Duke Energy prevailed and was awarded recovery of those costs in rates, as well as a return on those costs.

The Attorney General's theory of the case was that Duke Energy should not have stored CCRs in unlined basins (AG Br. pp 46-50); that it acted unreasonably in managing those basins in any event (*id*. at 50-52); and that, therefore, it should be allowed no recovery of its coal ash basin closure costs. The Commission was not persuaded by the Attorney General's presentation or his evidence and rejected his theory of the case. There is nothing in the rate making burden of proof framework that would require Duke Energy either to disprove the Attorney General's theory, or to adduce evidence to try and refute it. Duke Energy carried its burden, and it is therefore entitled to recover these expenditures.

Even if there is evidence in the record supporting the Attorney General's theory of the case, that simply is of no moment. In *State ex rel. Utils. Comm'n v. Eddleman*, 320 N.C. 344, 355, 358 S.E.2d 339, 347 (1987), this Court held that its "statutory function is not to determine whether there is evidence to support a position the Commission did not adopt. We ask, instead, whether there is substantial evidence, in view of the entire record, to support the position that the Commission *did* adopt." (Emphasis in original).

When the proper question – is there substantial evidence to support the Commission's determination – is asked, the answer is clearly "Yes."

In fact, even one of the dissenting Commissioners acknowledged that the Attorney General's burden of proof arguments went too far. First, Commissioner Clodfelter identified the logical consequence of the Attorney General's approach to the burden of proof issue: "[D]enying the Company all cost recovery for failure to carry its burden of proof would have severe financial consequences for the Company and would, as the majority points out, likely lead to the Company's having to pay even higher costs to secure equity and debt financing for future operations and investments, a result that would significantly harm ratepayers." (DEP R p 731). He went further, indicating also that such a result "would, I believe, fail the fundamental test set out in G.S. 62-133(a), requiring that the Commission's determination of rates be fair and reasonable not only to objecting parties and ratepayers, but also to the Company." (*Id*. at 731-32).

Second, dissenting Commissioner Clodfelter pointed out, "Complete disallowance of all coal ash disposal cost recovery on the ground that the Company has failed to carry its burden of proof also flies in the face of common sense. Had the Company's management of coal combustion wastes resulted in no exceedances of the state's 2L groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits, the record taken as a whole shows that the Company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR Rule and CAMA." (*Id*. at 732). Of course, a decision on rate setting or cost recovery that "flies in the face of common sense" could not possibly be characterized as resulting in "just and reasonable" rates, fair to customers but also to the utility.

C. <u>Substantial Evidence Supports the Commission's Determination that Duke Energy was Entitled to Recovery of Coal Ash Basin Closure Costs.</u>

The Commission's findings of fact are conclusive if supported by competent, material and substantial evidence. *State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 336 (1972). "Substantial" evidence is "more than a scintilla or a permissible inference … [and] means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *State ex rel. Utils. Comm'n v. Carolina Utility Customers Ass'n*, 348 N.C. 452, 460 (1998). In these cases, the Commission's factual determinations are amply supported by the evidence.

In *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 739 S.E.2d 541 (2013) ("Cooper I"), this Court faulted the Commission for failing to weigh conflicting evidence and, instead, merely summarizing that evidence and then announcing a conclusion. *Id*. at 493, 739 S.E.2d at 547. No such criticism may be leveled against the Commission with respect to the 2018 DEC Rate Case Order or the 2018 DEP Rate Case Order. As the Commission itself stated (DEP R p 621, DEC R p 1032), it "carefully considered all of the evidence, and the record as a whole" including all parties' post-hearing briefs, even though its Orders did not expressly address "every contention advanced or authority cited." These statements are supported by an examination of the Orders themselves. In the DEC Order, the discussion of coal ash cost recovery totals 118 pages, including 48 pages summarizing the extensive evidence submitted by all parties, and fully 67 pages of Commission discussion and determinations. For the DEP Order, the corresponding figures are 69 total pages, 35 pages summarizing the evidence, and 29 pages of discussion and determinations. In both Orders, the Commission thoroughly set out the contentions of the parties, its findings, the reasons for those findings, and the weight and credibility determinations it made in reaching the conclusions it reached. Inasmuch as its factual determinations are indeed based upon substantial evidence, those findings are conclusive and may not be disturbed on appeal.

Moreover, the Commission's findings support all the factual predicates necessary to support the Commission's conclusion – that Duke Energy had carried its ultimate burden of proof to show that the coal ash basin closure costs it incurred during the applicable Recovery Periods were recoverable in rates. With respect to recovery of the costs themselves, the factual predicate is that they were reasonable and prudently incurred in order to comply with the new legal obligations imposed upon Duke Energy as a result of the promulgation of the CCR Rule and the enactment of CAMA.[7]

A detailed analysis of the evidence supporting the Commission's ultimate conclusion that the coal ash basin closure costs were reasonable and prudently incurred follows. As is readily apparent, the evidence goes well beyond even "substantial." Indeed, as the Commission found the evidence in support of its conclusion is "compelling." (DEC R p 1110). Accordingly, the Commission's determination that the coal ash basin closure costs incurred by Duke Energy during the applicable Recovery Periods are recoverable in rates must be upheld.

In the DEC Case, the Commission found that DEC "met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing that the coal ash basin closure costs it actually incurred from 1 January 2015 through 31 December 2017 are recoverable and that a return, but one reduced to recognize a mismanagement penalty,[8] is warranted, and that the Commission with contrasting evidence on the merits, with exception addressed below, authorizes recovery." DEC R p 1090. In the DEP case, the Commission similarly concluded that DEP's "coal ash basin closure costs actually incurred over the period from 1 January 2015 through 31 August 2017 are (a) known and measurable, (b) reasonable and prudent,

---

[7] Duke Energy addresses the factual support for the issue of a return on these costs in Section II, below.

[8] The propriety of the management penalty is unchallenged by any party to this appeal.

and (c) used and useful, and, as such, that it is entitled to recover those costs [again, net of the DEP management penalty] in rates." (DEP R p 667).

In arriving at these findings, the Commission first determined that Duke Energy's pre-CCR Rule and pre-CAMA management historical practices "have generally comported with industry practices and then-applicable regulations, especially in this region of the country." (DEC R p 1090). The Commission considered the testimony of Duke Energy witness Kerin who testified that Duke Energy's coal ash practices were in line with industry peers and no other party was able to "specify how the Company should have acted differently in managing its coal ash, at which sites it should have taken those actions, and how much those actions would have cost the company." (*Id.*) The Commission also noted that Attorney General witness Wittliff presented "no credible evidence" showing that Duke's "engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time, other than his own, subjective judgments." (*Id.*) In fact, the Commission found that many of the documents produced by intervenors to challenge the appropriateness of Duke Energy's coal ash management demonstrated historically similar coal ash management practices, and thus supported in part the Company's position, for example:

- Los Alamos Laboratory Report (1979): "Much of the ash produced by coal ash combustion is discharged into ash ponds." (DEC Doc. Ex. 1414).
- EPRI Coal Ash Disposal Manual (1981): No coal ash was landfilled in either North or South Carolina; rather, all of it was stored in ponds. (DEC

Doc. Ex. 4186). Further, 81% of the coal ash produced in the Southeast was placed in ponds. (*Id*. at 3-8).

- EPA Report to Congress (1988): This Report (DEC Doc. Ex. 6367) confirms that the Company's disposal of coal ash in ponds conformed in large measure to industry practice. The Report refers to ponds as "surface impoundments" (*Id*. at 4-11, and notes that CCR waste management practices varied by region, and that in the South (EPA Region 4, which includes North and South Carolina) 95% of the plants manage their CCRs on-site. *Id*. at 4-23). The Report continues, "On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant." (*Id*.) It noted further that "access to abundant, inexpensive supplies of water … [in Region 4[9]] often made it economical to use this management option." (*Id*. at 4-20).

(DEC R p 1091). The Commission concluded that compelling evidence established that Duke Energy's coal ash management practices were in line with industry practice:

> The 1988 EPA Report also indicates that "until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems," and that "liner use has been increasing in recent years." Intervenors point to these statements to argue that the Company's continued use of unlined ponds was outside standard industry practice and is otherwise imprudent. The Commission disagrees. The Report notes, for example, that 87% of surface impoundments were unlined, and that neither North Carolina nor South Carolina required liners. It also notes that one-fifth of waste generated

[9] Both North Carolina and South Carolina are in EPA Region 4.

> by coal-fired power plants was reused, and "the remaining four-fifths are typically disposed in surface impoundments or landfills." The Report thus validates witness Kerin's testimony that "unlined basins were the industry standard" at that time. As he stated, "the EPA report focused on new landfills and surface impoundments, while DEC last constructed a new ash basin in 1982." This was six years before the EPA Report was submitted to Congress. As witness Kerin stated further, in the DEP case AGO witness Wittliff testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, "because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" Finally, witness Kerin's conclusion is supported by the preamble to the CCR Rule itself.

(*Id*. (transcript citations omitted)). The Commission also noted ample evidence in the DEP Case, particularly from witness Kerin, that DEP's coal ash management was in line with industry practice. (DEP R p 627).

Second, the Commission found that Duke Energy witness Kerin's testimony "established that in large measure the costs were reasonable and prudent." (DEC R p 1092). The Commission gave great weight to witness Kerin's testimony finding that he was "credible, demonstrated command of the subject matter (he testified, after all, that he had 'lived' with that 'company-specific subject matter every day for the past four years'), and the Commission determined in the 2018 DEP Rate Order that he has 'lived' this project since its inception,' and the Commission concludes that his conclusions were not dislodged after being subjected to vigorous cross-examination." (DEC R p 1092 (transcript citations omitted)). The Commission noted that witness Kerin provided "narrative summaries as to why, in his view, these costs were incurred and why the compliance actions which led to those costs were the most reasonable and cost-effective options given the applicable facts and circumstances. He maintained that [Exhibits 10 and 11 to his testimony], coupled with the balance of his testimony and exhibits, demonstrate that these costs are reasonable and prudent." (DEC R p 1038; DEP R p 626). The Commission also noted that even Attorney General witness Wittliff, in contradiction with the Attorney General's theory of the case, agreed that the costs incurred by the Company to comply with the CCR Rule were reasonable and prudent. (DEC R pp 1043, 1094).

Third, the Commission determined that these coal ash basin closure costs for which Duke Energy sought recovery were incurred to comply with the CCR Rule and CAMA. It noted that witness Kerin's testimony and "supporting exhibits describe costs expended to facilitate the Company's handling and storage of coal ash, so as to conform to the new legal requirements imposed on the Company resulting from the promulgation of the CCR Rule and the passage of CAMA." (DEC R pp 1092-93). Further, the Commission noted that "capital expenditures undertaken to enable compliance with the law qualify as 'used and useful,' in that the Company does not have the option to fail to comply, and, as indicated in the testimony of Company witness Wright, are routinely recoverable in rates." (DEC R pp 1092-93).

The Commission also extensively discussed the specific prudence challenges raised by the Public Staff. Witnesses Lucas (in the DEP Case) and Junis (in the DEC Case) predicated their disallowance recommendations on Duke Energy's entry into a settlement agreement with North Carolina's environmental enforcement agency, the Department of Environmental Quality ("DEQ"), contending that the settlement equated to an admission of liability by Duke Energy. The Commission had separately noted that Attorney General witness Wittliff "testified that the definition of industry standards is compliance with law" (DEP R p 663), and rejected the Public Staff's attempt to equate entry into a settlement with violation of law, holding that North Carolina law does not countenance such a conclusion and that the Public Staff itself had disavowed it in prior proceedings. (DEC R pp 1119-20; DEP R p 659). Public Staff witnesses Garrett and Moore testified that the Commission should disallow hundreds of millions of dollars in costs, based upon their review of Duke Energy's specific actions (or inactions) relating to its CCR/CAMA compliance, but these recommendations too were rejected by the Commission.[10] Characterizing some of the Garrett and Moore recommendations as "'perfect world' scenarios" (DEC R p 1133; DEP R p 665), and thus infected by hindsight, the Commission noted that:

> In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by Intervenor-retained consultants. *See*, *e.g.*, 1988 DEP Rate Order, at 29. The Commission certainly does not question the bona fides or expertise of Garrett and Moore; indeed, witness Kerin notes (and appreciates) that they "conducted a thorough and principled analysis" of the Company's CAMA/CCR Rule compliance costs, and that he agreed with "the majority of their conclusions." (Tr. Vol. 20, p. 56.) Kerin, however, has "lived" this project since its inception (*id*. at 32), and his testimony regarding the decisions made is entitled to great weight – more weight than post hoc evaluations from Garrett and Moore.

---

[10] The Commission did agree that a $9.5 million disallowance for imprudence should be applied to the DEP recovery (DEP R p 666) and that disallowance has not been challenged on appeal.

(DEP R pp 665-66; *see also* DEC R pp 1126-27). In doing so the Commission expressly rejected the Garrett and Moore disallowances "based upon the testimony of Company witness Kerin, which the Commission credits and to which the Commission attaches great weight." (DEC R p 1126.)

The Commission also noted that some of the Garrett and Moore recommendations were infeasible. (*See, e.g.*, DEC R p 1128; DEP R p 664). It held, consistent with the 1988 DEP Rate Case Order that provides the appropriate prudence framework, that "infeasible options" do not support a finding of imprudence. (DEC R p 1130; DEP R p 666). No party to these appeals, certainly not the Public Staff, whose positions the Commission rejected, takes issue with these findings and conclusions.

The Commission did not just accept Duke Energy's evidence on its face, but also carefully considered and analyzed the intervenor challenges to cost recovery, namely that the costs are not "reasonable and prudent" and "used and useful" or that the costs should be shared among shareholders and customers. (DEC R p 1033; DEP R p 622). For example, the Attorney General argues in these appeals that the Commission erroneously abdicated its duty to assess whether illegal conduct is unreasonable and disallow costs related to illegal conduct. (AG Br. pp 53-59.) The Commission is not an environmental regulator; DEQ is an environmental regulator – and DEQ (represented by the Attorney General) has never proven that the conduct of which the Attorney General complains "violated" the law. For this reason, the Attorney General's reliance on the *Glendale Water* case (*State ex rel. Utils. Comm'n* *v. Public Staff*, 317 N.C. 26, 343 S.E.2d 898 (1986), *see* AG Br. pp 53-54) is entirely misplaced. Unlike in *Glendale Water*, there was no finding in the litigation brought against Duke Energy by DEQ, or admission by Duke Energy in that litigation, that any "violation" had actually occurred.[11] The "evidence" of violation presented by the Public Staff rather was that settlement of the litigation was tantamount to an admission of liability (*see* p. 33, above), which the Commission found lacking.

Regardless, the Commission carefully considered this argument raised by the Public Staff and determined that based on the evidence reviewed, "with the exception of the federal criminal case to which DEP pled guilty, DEP had not been found liable for violations of the law" and in regard to the seeps located at its ash basin sites, the Commission noted that "DEQ and DEP have been in long-standing negotiations as to whether seeps are a violation of law" and "DEQ has currently not made a determination on this issue." (DEP R p 663). The Commission found Duke Energy witness Wells testimony "persuasive" and "instructive" on this issue in coming to its determination "that any past violations by the Company do not give support to the amount of cost disallowances advocated by the intervenors and Public Staff in this case." (DEP R pp 661, 663). Specifically, in reaching its conclusion, the Commission relied on testimony provided by witness Wells, who indicated that

---

[11] The Attorney General's hyperbolic characterizations of the Commission's actual findings are, of course, entitled to no weight whatsoever. *See*, *e.g.*, AG Br. p 53 (Commission "concluded that it is legal under the 2L rules to pollute groundwater"). The Commission made no such finding, and the question to be answered in these appeals is "Are the Commission's actual findings supported by substantial evidence?" The answer is "Yes."

under the groundwater standards an exceedance does not immediately result in a Notice of Violation and penalty; rather, "the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action." (DEP R p 661). The exceedances are not "violations" because, as Wells testified, "the 2L rules' corrective action provisions are designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process." (*Id*.). Concluding its discussion on this issue, the Commission found Wells' testimony persuasive:

> [T]he groundwater extraction and treatment activity that DEP performed pursuant to the DEQ Settlement Agreement merely accelerated work that would have been required under CAMA in any event. Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by exceedances – not violations – of the 2L groundwater standards. In other words, unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

(DEP R p 662 (transcript citations omitted)).

Similarly, in the DEC case, the Commission disagreed with the Public Staff's position regarding alleged environmental violations. (DEC R p 1119). The Commission stated that it "does not find DEQ exceedance reports or SOCs to constitute compelling evidence of environmental violations." (*Id*.). Consistent with its analysis of alleged environmental "violations" in the DEP 2018 Rate Case Order, the Commission specifically rejected the Public Staff's assertion that Duke Energy's settlement with DEQ evidenced such violations. It noted that the settlement agreement "references in its recitals a DEQ 'Policy for Compliance Evaluations' promulgated in 2011, and [that] it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred" at all. (*Id*. p 1121). The Commission noted further that the recitals in the settlement agreement "also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA 'dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina' … [and that] the CAMA requirements were 'designed to address, and will address, the assessment and corrective action' associated with alleged groundwater contamination." (*Id*.). Based upon this analysis, the Commission again concluded, as it had in the DEP 2018 Rate Case Order, that:

> Because CAMA would require the Company to implement certain actions, the Commission determines as it did in the 2018 DEP Rate Order that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation.

(*Id*.).

Witness credibility is for the Commission, not this Court, to determine. *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 575, 584, 232 S.E.2d 177, 183 (1977) ("The credibility of [a witness's] testimony and the reliability of … expert opinion based thereon are matters for the determination of the Commission, not the reviewing court."). The Commission found the testimony of Duke Energy witnesses Kerin and Wells to be credible, probative, and worthy of acceptance. It concluded that the testimony of the Public Staff witnesses, as well as Attorney General witness Wittliff, was not persuasive. The conclusion the Commission came to, namely that Duke Energy had carried its burden of proof to show that the coal ash basin closure costs it incurred during the applicable Recovery Periods were reasonable and prudent, is supported by substantial evidence and, therefore, conclusive in these appeals. Accordingly, the Commission's determination that recovery of those costs in rates is not error and should be upheld.

II. THE COMMISSION APPROPRIATELY AUTHORIZED A RETURN ON INVESTOR-FUNDED COAL ASH BASIN CLOSURE COSTS THAT THE COMMISSION FOUND WERE REASONABLE AND PRUDENTLY INCURRED

The second issue presented in the Attorney General's appeal is whether the Commission erred in allowing a return on the coal ash basin closure costs Duke Energy incurred in the applicable Recovery Periods, and which the Commission determined should be recovered in rates. (AG Br. p 2). The Public Staff also makes the argument that a return is inappropriate. (Public Staff Br. pp 48-130).

Neither argument has any merit. First, the modification of the coal ash basin system stands as property that is "used and useful," thereby justifying a return.

Second, the factual predicates underlying the propriety of a return have been met: the coal ash basin closure costs were appropriately deferred; the costs were properly capitalized as "utility plant" under ARO accounting; and the costs were paid through investor-supplied funds and have not been recovered through rates. Because these investor-funded costs will not be fully recouped through rates until the end of the five-year amortization period (*i.e.*, until 2023), the Commission appropriately allowed a return on the capital supplied by debt and equity investors to fund Duke Energy's coal ash basin closure costs.

A. <u>Property "Used and Useful" in the Provision of Electric Service is not Confined to Physical Plant but Encompasses all Forms of Property That Support and Provide Service to Utility Customers.</u>

North Carolina General Statutes Section 62-133 does not define the phrase "public utility's property used and useful." Appellants imply that this Court should construe this phrase narrowly. The Public Staff, for example, asserts – without citation – that "'property' primarily means 'utility plant' that consists of long-lived assets used to provide utility service." (Public Staff Br. p 51). The Public Staff refers to "property" as including "brick and mortar buildings, generators and utilities, poles, meters, and conductors such as transmission, distribution, and service wires that carry electricity from generators to customers." (*Id.* at 50-51).

The statute does not restrict "property" to simply generators and wires. The term includes all assets necessary to provide electricity to the public. It includes, for example, inventory of fuel that should be held as a reserve, as well as cash that should be kept on hand to pay the utility's bills as they become due. (DEC R pp 837 n.4, 824, 904). Fuel costs are normally operating expenses. In the case of reserve fuel, however, these "operating expenses" are included in the rate base (and entitled to a return on investment) because the reserves are investor-funded. In the case of cash working capital, the asset (cash reserves) does not generate electricity – but it is property that is necessary and appropriate for providing electricity to customers. What stands as "property used and useful" does not turn on whether the property generates electricity, but whether it serves the public and was paid by debt or equity investors – rather than through rates that were set in anticipation of normal operating expenses.

In *Utilities Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 414-15, 206 S.E.2d 283, 295-96 (1974), this Court expressly recognized that when a utility keeps on hand a reasonable amount of shareholders' funds (in the form of cash) to pay operating expenses, such working capital constitutes property that is used and useful in providing retail electric service and should be included in rate base. In that case, the Utilities Commission concluded that the reasonable amount of funds that VEPCO should have available to pay operating expenses as they became due was $1.9 million. Because this cash constituted working capital provided out of shareholder equity, VEPCO was entitled to earn a return on the cash that was needed to pay operating expenses. This Court concluded:

> While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service," as used in G.S. 62-133(b) (1), and are a proper addition to the

> rate base on which the utility must be permitted to earn a fair rate of return.

Id. Thus, to the extent that Appellants or their experts assert that "property used and useful" is limited to a utility's physical plant, that position is contrary to North Carolina law. (*See* DEC T Vol 22, p 77).

The *VEPCO* decision is based on sound economics. Barring extraordinary circumstances, operating expenses are paid through electricity rates (which are set at a level to cover operating expenses). When extraordinary expenses arise that justify deferral accounting, those expenses are paid – not through electricity rates set in anticipation of those expenses – but by funds invested by the utility's debt and equity investors. As the Public Staff notes, when operating expenses are recovered through rates, the statute does not provide for a return on investment for those operating expenses. (Public Staff Br. p 54). The Public Staff reluctantly concedes, however, that when extraordinary expenses are incurred (that were not built into rates), the Commission has discretion to allow a return on investment if those expenses have been deferred to the next general rate case.[12] (*Id.* at 55-57; *accord* DEC T Vol 22, pp 78, 137-138).

---

[12] This Court's decision in *Utilities Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 414-15, 206 S.E.2d 283, 295-96 (1974) provides that "the utility must be permitted to earn a fair rate of return" on working capital. Whether the Commission is required to award a fair rate of return on investor-supplied capital (or simply has the discretion to do so) is not material to the outcome of this appeal. As set out below, the Commission's decision to allow Duke Energy a fair rate of return on coal ash basin closure costs paid through investor funds is not arbitrary and capricious. Duke Energy does not concede that the award of a fair rate of return on these expenses is discretionary – rather than mandatory. Under the Commission's holding, however, this distinction is essentially academic.

A substantial difference exists between operating expenses that are built into rates and are paid by customers versus extraordinary costs that must be advanced by debt and equity investors. Under the Public Utilities Act, a public utility (and its investors) receives no rate of return on operating expenses that are paid by customers at or about the time the operating expenses are incurred by the utility. Because normal operating expenses are built into rates, those expenses are not investor-funded requiring a fair rate of return. When operating expenses are paid by customers (through rates) as the utility's operating expenses become due, the utility does not need to attract investor capital to fund those expenses. Consequently, there is no cost of capital associated with those operating expenses. When, however, the utility advances funds to pay for expenditures not already built into rates, that capital does not come from current rates, and is therefore investor-funded. If the utility is not allowed a fair rate of return on capital funded by its investors, the utility will be at a competitive disadvantage in raising investment funds in the future, and its borrowing costs and cost of equity capital will increase.

The new rates approved by the Commission for DEP had an effective date of 16 March 2018. The rates approved for DEC had an effective date of 1 August 2018. Rates in effect prior to those effective dates did not include the coal ash basin closure costs incurred by Duke Energy for which it sought recovery in these cases. As a result, Duke Energy through its investors advanced $778 million (as adjusted for disallowances) to comply with the new regulatory requirements relating to coal ash basins. Duke Energy's investors will continue to incur the costs of providing these funds until the end of the five-year amortization period (albeit in diminishing amounts as these costs are recouped over the five-year period through rates).[13] Because this $778 million had not been factored into the prior rates, these costs were, by definition, paid from investor funds. As the Commission concluded, the funds advanced by the utility to comply with the CCR rules and CAMA "are investor-supplied funds, not rate-payer supplied funds and under principles of equity, law and fairness are eligible for a return [on investment.]" (DEC R p 1100). The Commission recognized that failure to allow a return on investment on these investor-supplied funds would deprive investors of the time value of money on these funds. (*Id.*) Denying a return on this capital would increase the risk of investing in the Company, "ultimately increasing the Company's cost of capital." (*Id.*) This conclusion is grounded in the record evidence and the Commission's expertise and cannot be fairly characterized as arbitrary and capricious. Moreover, the Commission's explanation for why it exercised its discretion to permit a return on this investment is set out in great detail in its orders. (DEP R pp 497-498, 621-685;

[13] As used in this rate case proceeding, "amortization" simply refers to the repayment of these capital costs over time. Here, Duke Energy proposed that the Commission authorize Duke Energy to spread over time the coal ash closure costs incurred between 1 January 2015 and 31 December 2017. Amortizing these costs over a five-year period helps to mitigate the rate impact on consumers. At the conclusion of the five-year amortization period, the utility will have recouped these costs (including investment opportunity costs), and these costs will no longer be included in rates. Conversely, if the closure costs had been immediately added to rates as they were paid by the utility, there would be no costs advanced by shareholders and no increase in the capital cost of plant utilities. As reflected by the absence of objections to Duke Energy's request for a deferred accounting, the Commission and all interested parties believed that consumers would be better served by amortizing these costs over time rather than asking ratepayers to fund these expenses as they were incurred.

DEC R pp 847-848, 1031-1147). The funds supplied by Duke Energy and its investors are therefore "property used and useful" in the provision of service to customers.

B. The Commission Appropriately Authorized Deferral of Coal Ash Basin Closure Costs for Later Inclusion in Rates.

The Commission's decision to defer Duke Energy's coal ash basin closure costs is not challenged in these appeals. Nevertheless, it is a critical building block for the Commission's decision to allow Duke Energy a return on such costs. The Commission's deferral determinations in these cases are supported by substantial evidence and are fully in compliance with applicable legal precedent.

1. Substantial Evidence Supports the Commission's Authorization of the Deferral.

In Docket No. E-2, Sub 1103 ("DEP Deferral Docket"), DEP requested that the Commission issue an accounting order deferring its coal ash basin closure costs. (DEP R p 617). That Docket was consolidated with the DEP Rate Case, and in the DEP Rate Case Order the Commission held that deferral of prudently incurred coal ash basin closure costs was appropriate based upon its long-standing deferral requirements. (DEP R pp 617-20). It so held largely on the strength of the testimony of two normally opposing witnesses – DEP witness Bateman, and Public Staff witness Maness. The Commission gave their testimony "significant weight." (DEP R p 620).

Thus, for example, witness Maness testified that "based on the magnitude and unique nature" of the coal ash basin closure costs "the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred." (DEP R p 617). Witness Maness also referenced comments that the Public Staff had filed in the DEP Deferral Docket as additional support for its position approving of the deferral. (*Id*.) In those comments Public Staff had supported deferral for regulatory accounting purposes because the costs generally satisfied the criteria for deferral accounting in that they were "adequately extraordinary in both type of expenditure and in magnitude to justify consideration for deferral …[and] the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant." (*Id*.) Witness Bateman also supported deferral, indicating that new environmental laws and regulations "had significantly increased the estimated closure costs of the Company's CCR basins, and changed the required accounting, triggering asset retirement obligation accounting." (*Id*.)

Similarly, in Docket No. E-7, Sub 1110 ("DEC Deferral Docket"), DEC requested that the Commission issue an accounting order deferring its coal ash basin closure costs. (DEC R p 1031). That Docket was consolidated with the DEC Rate Case, and in the DEC Rate Case Order the Commission held that deferral of prudently incurred coal ash basin closure costs was appropriate based upon its long-standing deferral requirements. (DEC R pp 1030-31). The Commission's determination again relied heavily on the Public Staff's acceptance of the propriety of deferral in the DEC Deferral Docket and on witness Maness's testimony (which was essentially identical to his DEP Rate Case testimony). (*Id*.)

2. Deferral of Duke Energy's Prudently Incurred Coal Ash Basin Closure Costs is Fully Supported by Applicable Law.

Historically, the Utilities Commission and this Court have allowed deferral when a utility has incurred extraordinary expenses not included in rates. *In re Request for Approval of Accounting Treatment*, Docket No. E-13, Sub 158 (N.C. Util. Comm'n 1992). Similarly, deferral has been used when reductions in the utility's costs are anticipated in the future but cannot be reasonably calculated. *See, e.g., State ex rel. Utilities Comm'n v. Carolina Utility Customers Ass'n*, 314 N.C. 171, 333 S.E.2d 259 (1985) (deferral accounting in anticipation of uranium fuel savings). The Commission has described cost deferrals as "a recognized practice allowing recovery of unusual expenses arising from extraordinary circumstances or events." *In re Application by VEPCO*, Docket No. E-22, Sub 532 at 162 (N.C. Util. Comm'n Dec. 22, 2016). Deferral allows the Commission to ensure that the magnitude of extraordinary costs is better understood before including those costs in rates. More importantly, deferral allows the Commission to minimize rate impacts on the consuming public. (*See* DEC R pp 14-15 (noting that deferred accounting can be used to establish an "amortization schedule to mitigate rate impact")).

The impact of the Commission's deferral determinations is also undisputed:

> The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. *Id*. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. *Further, if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again*

> *impairs the Company's ability to earn at its authorized rate of return*. Rates that impair the Company's ability to earn its authorized return are not just and reasonable, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

(DEC R p 1114 (Emphasis added)). As shown below, it is for this reason that a return on the deferred costs during the period (5 years in these cases) in which the costs are amortized and recovered is appropriate.

C. **<u>The Commission Correctly Determined that the Coal Ash Basin Closure Costs were Appropriately Accounted for and Capitalized as Asset Retirement Obligations under GAAP-Mandated Rules.</u>**

The Attorney General and the Public Staff argue that Duke Energy should not recover a fair return on the funds advanced by shareholders to cover coal ash closure costs. (*See, e.g.*, AG Br. p 70; Public Staff Br. p 75). Public Staff asserts that at least some of the coal ash basin closure costs incurred by Duke Energy were "operating expenses" and therefore ineligible for a return. (Public Staff Br. p 75). The Attorney General's position is that these costs are really "waste management expenses" and not eligible for a return. (AG Br. p 68).[14]

---

[14] The Attorney General cites *Fla. Cities Water Co. v. Fla. Pub. Serv. Comm'n*, 705 So. 2d 620 (Fla. Dist. Ct. App. 1998) as support for its contention that the costs incurred by Duke Energy are really "expenses." (AG Br. pp 77-79). How the courts of Florida and the Florida Public Service Commission classify costs is of course irrelevant for purposes of these cases. Rather, the North Carolina Public Utilities Act and the decisions of this Court construing the Act supply the rule of decision in these cases. Further, while the Florida Court of Appeals held it is not the case that all expenditures made to comply with a regulation may be incorporated into the rate base, the court stated "We hold that the PSC must, in considering what to include in the rate base, treat capital improvements required by governmental regulations as 'in the public interest,' … but that the PSC must add these expenditures to the rate base only to the extent the improvements they effect or the facilities to which they relate are 'used and useful in the public service.'" *Fla. Cities Water Co. v. State*, 705 So. 2d 620, 623 (Fla. Dist. Ct. App. 1998).

These arguments lack merit. As the Commission found: "Costs placed in an ARO account are eligible for deferral and amortization and for earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets." (DEP R p 675). The Commission's conclusion is correct, and its findings are supported by substantial evidence and therefore conclusive in these appeals. Those findings completely reject the notion that Duke Energy's coal ash basin closure costs should properly be classified as "expenses" ineligible for a return.

1. Under Required Accounting Procedures, the Investor Funds That Were Advanced for Coal Ash Basin Closure Were Properly Capitalized.

The legal and accounting foundations of the Commission's ARO decision show that the Commission's determination is correct under applicable law. There is no error in the Commission's analysis in this regard.

The regulations of the Securities and Exchange Commission ("SEC") require Duke Energy, as a publicly-traded company, to comply with GAAP, as well as Financial Accounting Standards ("FAS") and Accounting Standards Codification ("ASC") set by the Financial Standards Accounting Board ("FASB"). (*See* DEC R p 1108 n.70). Duke Energy is also subject to the accounting procedures adopted by the Federal Energy Regulatory Commission ("FERC"). (DEC R p 1108; DEC T Vol 12, p 62; *see* 18 C.F.R. § 101 (FERC Uniform System of Accounts)). The Commission has directed electrical utilities in North Carolina to follow the accounting and reporting requirements prescribed by FERC. NCUC Rule R8-27.

An ARO is defined by FERC as "a liability for the legal obligation associated with the retirement of a tangible long-lived asset." 18 C.F.R. § 101, General Instr. No. 25. As relevant here, an ARO must be recorded on a utility's books and records "when a change in the law creates a legal obligation to perform the retirement activities." 68 Fed. Reg. 19610, 19611 (Apr. 21, 2003). Thus, when "it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins," the Company was required to follow the accounting requirements relating to AROs. (DEP R p 673).

When an ARO is mandated, the utility is required to record the ARO as a liability on its balance sheet. 68 Fed. Reg. at 19611. A corresponding entry in the same amount is made on the asset side of the company's balance sheet to reflect the increase in the "cost of the related asset that gives rise to the legal obligation." *Id.* The bookkeeping entries required by the SEC and FERC (and the Utility Commission by incorporating FERC accounting requirements) are the same. *Id.* (noting that ARO accounting procedures required by FERC are "consistent with the accounting and reporting requirements" of the SEC).

The effect of the accounting procedures required by FERC and the SEC is to "capitalize the asset retirement costs" – with the obligation being recorded on the balance sheet as a <u>liability</u> and an identical entry being added to the balance sheet as an <u>asset</u> (as an increase in the cost to the asset, *i.e.*, utility plant, that gives rise to the obligation). *Id.* ("companies will separately account and report the liability for the asset retirement obligations, <u>capitalize the asset retirement costs</u>, charge earnings for depreciation of the asset and charge operating expenses for the accretion of the liability") (emphasis added); *see* Adrian Fitzsimons & Irene McCarthy, *Accounting for Asset Retirement Obligations,* Commercial Lending Review 70, 70 (Winter 2001-02). FERC directs that in capitalizing asset retirement costs they shall be recorded in the account "electric utility plant" as an asset. 18 C.F.R. § 101, General Instruction 25(B). In its preamble to its rules, FERC emphasizes that "asset retirement costs are considered an integral part of the costs of the particular asset that gives rise to the asset retirement obligations, rather than separate and distinct assets." 68 Fed. Reg. at 19615.

As the Commission explained in its DEC order:

> [B]oth GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired.

(DEC R p 1112). The SEC, FERC, FASB and the Commission properly recognize that the costs associated with retiring a utility plant are an integral part of the utility plant itself. As a result, all require that these costs be capitalized and accounted for as an asset of the company. This direct relationship between asset retirement obligations and utility plant property amply justifies the Commission's conclusion that the expenditures at issue are no different from the costs to build the utility plant and therefore stand as the "public utility's property used and useful." N.C. Gen. Stat. § 62-133(b)(1).

Capitalized costs bear a return. The coal ash basin closure costs incurred by Duke Energy are capitalized costs, funded by Duke Energy's investors, who advanced the funds expecting a return. The Public Utilities Act provides for a return, and the Commission properly awarded one.

2. The Commission's ARO Determination is Supported by Substantial Evidence.

The Commission's analysis of the legal and accounting foundation of its ARO decision is also amply supported by substantial evidence. Before the Commission, the Public Staff took the position that the costs accounted for in the coal ash basin closure AROs established by Duke Energy were more properly classified as "deferred expenses," and, therefore, not eligible for a return once those costs were brought into rates. (DEC R p 1107). The Commission comprehensively addressed the Public Staff's position in its factual findings. In doing so, it is clear that this Court's *Cooper I* criticism – the Commission's failure to weigh conflicting evidence and, instead, merely summarizing that evidence and then announcing a conclusion, *see* 366 N.C. at 493, 739 S.E.2d at 547 – does not apply to the Commission's ARO discussion in these cases. That discussion is thorough, complete, and extensively weighed the Public Staff's position, as advanced by its witness Maness, with Duke Energy's position as advanced by its witnesses Doss and McManeus. (*See, e.g.*, DEC R pp 1107-1116). The Commission rejected Public Staff witness Maness' testimony and credited the testimony of Company witnesses Doss and McManeus. That determination is for the Commission, and its determination is not subject to challenge on appeal, so long as supported by substantial evidence. Given the extensive discussion of the supporting evidence by the Commission, the Commission's determination *is*, in fact, supported by substantial evidence.

The Commission began that analysis by noting that witness Maness started "from the premise that the Company 'chose' to account for its coal ash basin closure costs through ARO accounting" (DEC R p 1107), but disagreed with that premise. It held, to the contrary, that "Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter." (DEC R pp 1107-08; DEP R p 673). Not only was ARO accounting required by GAAP, but Duke Energy "was also required to (and did) adhere to and apply the accounting guidance under … [the] Federal Energy Regulatory Commission ('FERC') Code of Federal Regulations ('CFR'), as well as Orders of this Commission." (DEC R p 1108). The Commission then, relying upon and crediting witness Doss, detailed the GAAP and FERC rules, as well as its prior Orders, that governed and informed its analysis.

With respect to GAAP, the Commission found, based upon Doss' testimony, that "[t]he CCR Rule and CAMA were new laws that compelled basin closure under GAAP." (DEC R p 1108). Doss' testimony detailed the specific GAAP guidance implicated for coal ash basin closure costs, and in particular Subtopic 15-2 in ASC 410-20-15. (DEC R pp 1108-09). As the Commission found:

> Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of

> Subtopic 15-2(b). As noted in Company witness Kerin's testimony, the use of ash impoundments as a storage location for coal ash and other CCR was in accordance with industry standards and then-applicable regulations.

(DEC R p 1109). Indeed, the Commission found specifically that the coal ash basin closure costs for which Duke Energy sought recovery resulted "from the 'normal,' non-catastrophic operation of the Company's coal ash basins," and it called the evidence supporting this proposition "compelling." The Company has proven that its coal ash management practices, storage of CCR in unlined ash basins, complied with the then-applicable regulations and with industry practice. Seepage from unlined basins is therefore part of the 'normal operation' of those basins." (DEC R p 1110).[15]

The Commission found witness Doss' explanation of the FERC rules and prior deferral orders of the Commission to be equally compelling. (DEC R pp 1110-11). It concluded by summarizing its findings:

> While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – *the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired.* While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723,[16] the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further

---

[15] This evidence is detailed in Section I.C, above, and, indeed, is "compelling."

[16] The corresponding DEP order is in Docket E-2, Sub 826.

> order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

(DEC R p 1112) (emphasis added). The Commission's summary is fully supported by the testimony of witness Doss. No witness contradicted Doss' recap of the applicable GAAP, FERC, and deferral rules.

The Commission went on to examine the underpinnings of the DEC Deferral Docket, and, in particular, the Company's letter that led the Commission to initiate that Docket – what the Commission referred to as the "Savoy Letter." (DEC R pp 3-11, 1112).[17] The letter, dated 21 December 2015, from a senior accounting officer of both DEC and DEP:

- Describes the GAAP and FERC accounting requirements regarding AROs;
- Describes the triggering events for the creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA;
- Indicates that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet;
- Indicates further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets"; and
- Noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 … [and Order dated August 12, 2003 in Docket E-2, Sub 826 – the equivalent DEP general deferral Order] all income statement impacts relating to the AROs ultimately reside in regulatory asset accounts."

[17] The Savoy Letter, which applied to both DEP and DEC, was also the trigger for the Commission's initiation of the DEP Deferral Docket. (DEP R p 3).

(DEC R p 1112). The Commission indicated that Duke Energy witnesses were examined at length regarding the Savoy Letter (*see* DEC T Vol 9, pp 117-24), and that that examination "established, *inter alia*, that basin closure costs, whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO; that such costs are extraordinary and not reflected in the Company's then-current rates; and, therefore, needed to be set aside and deferred so that the Company would not lose recovery of those costs 'to the detriment of the stockholder.'" (DEC R pp 1112-13).

The Savoy Letter is entirely consistent with witness Doss' testimony – indeed, it foreshadowed that testimony by approximately two years. This congruence was not lost on the Commission: "Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's [prior deferral] orders …. Neither the Public Staff nor anyone else, including the … [Attorney General], raised any objection." (DEC R p 1113). Indeed, as the Commission found, "No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter." (*Id*.)

On this basis, the Commission concluded that Duke Energy "met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO accounting." (DEC R p 1113). That conclusion is supported by substantial evidence, as shown above.

In reaching this conclusion, the Commission found that Public Staff witness Maness' argument that the costs in the ARO were properly classified as deferred expense was "not persuasive, not supported by authority, and not determinative, given the nature of the deferral." (DEC R p 1113). But the Commission found that Maness' position was also "incorrect as a matter of accounting," noting that "because under GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not expense." (DEC R pp 1113-14).

The Commission clearly set out the consequences for its finding, supported by substantial evidence, that Duke Energy's coal ash basin closure costs were properly and appropriately accounted for in an ARO. It noted that "deferred costs are costs 'that have been paid for by the … [utility] but have yet to be included for ratemaking purposes.'" (DEC R p 1113, *quoting* Lesser & Giacchino, p 52). Then, crediting Company witness McManeus, the Commission quoted her testimony:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

(DEC R p 1114, *quoting* DEC T Vol 6, p 317). The Commission noted that McManeus "elaborated further, indicating that the 'characteristic that makes the deferred coal ash cost a legitimate component of rate base' is the fact that the funds used to pay those costs were supplied by investors. (*Id*., *citing* DEC T Vol 6, p 318).

In these cases, there were two deferral periods. In the first deferral period, coal ash basin closure costs were deferred from the time they were incurred until the costs began to be recovered in rates – 16 March 2018 for DEP, and 1 August 2018 for DEC. In the second deferral period, these costs were deferred (albeit on a declining basis) over the five-year amortization periods during which they are to be recovered in rates. In both the DEC and DEP cases, the Public Staff not only supported the deferral of Duke Energy's coal ash basin closure costs, it supported adding a return to those deferred costs during the first deferral period at the applicable Company's weighted average cost of capital. (DEP R p 87; DEC R p 87). In fact, in both cases Public Staff witness Maness testified that he added that return to the deferred costs (DEP T Vol 18, p 307; DEC T Vol 22, p 69), and, as the Commission noted, no party objected to the inclusion of that return in the proceedings below. (DEC Tr Vol 9, p 128).

The Public Staff therefore recognized that the investor-supplied capital used to fund Duke Energy's coal ash basin closure costs during the first deferral period should earn a return. That same investor-funded capital should also earn a return in the second deferral period, as those same costs are brought into rates during the five-year amortization periods. The Public Staff never adequately explains the inconsistency in its position.

D. Appellants' Arguments that the Commission Erred in Allowing Duke Energy to Recover a Return on Coal Ash Basin Closure Costs Advanced by Investors Lack Merit.

On 15 occasions in his brief, the Attorney General argues that Duke Energy should not be permitted to "profit" from closure of the coal ash basins. (AG Br. pp 2, 5, 15, 39, 43, 68, 72, 93, 95). He even goes so far as to label these as "windfall profits." (AG Br. p 40). Such rhetoric, however, ignores the fact that the North Carolina Public Utilities Act directs the Commission to establish a "rate of return" that will allow a utility to maintain its facilities and services, "compete in the market for capital funds on terms that are reasonable and that are fair to its customers," and to produce a "fair return for its shareholders." N.C. Gen. Stat. § 62-133 (emphasis added). To characterize the "rate of return" mandated by the statute and the Constitution as "windfall profits," trivializes and ignores the regulatory compact that has served this State well for decades. *The Binghamton Bridge*, 70 U.S. 51 (1865) (when a State authorizes a public utility to accommodate a public necessity, the State agrees to protect the privileges granted to the utility that justify the utility's expenditures). Establishing rates that do not allow the utility to recover its cost of equity capital constitutes an unconstitutional taking of property. *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). More importantly, the Attorney General wholly ignores the General Assembly's directive that rates must be set at a level that allow the utility to "compete in the market of capital funds." N.C. Gen. § 62-133. No utility that advances $778 million dollars to customers over an eight-year period with no return on that investment could possibly compete in the market for capital funds on reasonable terms.[18]

1. The Attorney General's Argument that the Closure Costs were not Paid by Investor Funds is Meritless.

Appellants argue that Duke Energy has not sufficiently established that the funds that were paid from 1 January 2015 to 31 December 2017 for closure costs were investor funded. This argument is wholly devoid of merit.

The Attorney General makes the extraordinary claim that Duke Energy "did not show that it relied on new investors to pay its coal-ash costs." (AG Br. p 90). Unquestionably, coal ash closure costs from January 2015 to December 2017 were not included in the calculation of rates prior to the present rate case proceeding. Rates are set based on operating expenses during a test year. The other calculus going into rates, of course, is the utility's property used and useful (less depreciation) times a reasonable rate of return. The rates in effect prior to the present rate case proceeding were determined based on a test year period consisting of the twelve months ended 2012 March 31 for DEP and the twelve months ending 30 June 2012 for DEC. None of the closure costs at issue in the appeal occurred during that period. Because coal ash closure costs (covering the period of January 2015 to December

[18] The coal ash basin closure costs began on 1 January 2015. The five-year amortization period for these costs will conclude in July 2023. Thus, the period that the Attorney General believes that investor funds should be denied a fair rate of return is eight years, seven months.

2017) had not been factored into rates at the time the coal ash costs were incurred, these costs were by necessity paid out of shareholder equity. As a matter of basic accounting and common sense, if a utility's revenues do not include an amount to account for extraordinary costs, those costs are being paid for by shareholders.

The Attorney General's reference to "new investors" also makes no sense. As this Court recognized in *VEPCO*, if "the utility's own funds" are invested in working capital, a return on those funds is permitted. 285 N.C. at 414-15, 206 S.E.2d at 295-96. The *VEPCO* decision makes no reference to "new investors" – nor does the Public Utilities Act. The Attorney General's assertion that the utility must prove that the investor funds that paid for these extraordinary expenses came from "new investors" is not supported by this Court's precedent or the statute. Moreover, it is not supported by basic economic principles. When shareholder equity is consumed to pay for extraordinary expenses, that shareholder equity is not earmarked for a specific shareholder – whether a new shareholder or an existing shareholder. Rather, shareholder equity is fluid. Millions of shares of the company's stock can be bought and sold in a single day. From an economic perspective, the crucial point is that when a public utility is forced to bear extraordinary costs for which it does not receive revenue, both shareholder equity and the value of the company decline. That makes it harder and more costly for the company to obtain additional capital in the market. The Attorney General's reference to "new investors" is nothing more than a red herring.

The Attorney General also glosses over the fact that ample testimony demonstrates that the coal ash basin closure costs were investor-funded. Consistent with the way rates are determined and the economic principles discussed above, numerous witnesses testified that the payment for coal ash closure costs came from investor funds. The Public Staff's own witness testified: "The utility has already spent the money represented by the deferred cost in question, therefore, it will be required to borrow money or use equity to finance the spent cost until it can be recovered from ratepayers." (DEC T Vol 22, pp 82-83). The Public Staff (which is charged with protecting the interest of the consuming public) recognizes that a return on investment is permitted. (Public Staff Br. pp 55-57). The Company's witness (Jane McManeus) confirmed the testimony of the Public Staff that the coal ash closure costs were funded through a combination of debt and equity. (DEC T Vol 10, pp 14-15). Witness McManeus testified: "[I]nvestors have advanced funds to pay for coal ash compliance costs." (DEC Tr Vol 6, p 317). She further testified that these compliance costs were not built into rates and were not paid for by customers. (*Id.*) Ample evidence supports the Commission's finding and conclusion that these costs "are not being recovered through current rates" and that money used by the utility to pay these funds are "investor-supplied funds, not rate-payer supplied funds." (DEC R p 1100).

2. Appellants' Reliance on Precedent Relating to Abandoned Plants is not Relevant.

Citing to *Utilities Comm'n v. Public Staff*, 333 N.C. 195, 424 S.E.2d 133 (1993) ("*Carolina Trace*"), *Utilities Comm'n v. Thornburg*, 325 N.C. 484, 385

S.E.2d 463 (1989) and *Utilities Comm'n v. Carolina Water Service*, 335 N.C. 493, 439 S.E.2d 127 (1994), Appellants assert that these cases hold that a return on investment is only appropriate when property is currently in use to generate electricity. (*See* AG Br. pp 86-87). These cases are readily distinguishable and do not support the Appellants' position.

In *Carolina Trace*, the utility installed a sewer connection to the City of Sanford but discontinued use of the connection before its next general rate case. This Court concluded that the abandoned sewer connection was not "used and useful property" at the time of its general rate case and could therefore not be included in rate base. In *Thornburg*, this Court concluded that the portion of common facilities at the Shearon Harris Nuclear Plant that were built to accommodate reactors that were later abandoned are excess facilities. Consequently, these excess facilities could not be included in rate base. In *Carolina Water Service*, this Court held that a wastewater treatment plant that was not in service at the end of the test year (and that would never again be in service) should not be included in rate base.

The present appeal does not involve excessive facilities tied to nuclear units that were never completed and never used to generated electricity (e.g., *Thornburg*). Moreover, this rate case does not involve abandoned utility plants and equipment that no longer result in costs to the utility (e.g., *Carolina Trace* and *Carolina Water Service*). Here, the investor-funded expenditures have a direct relationship to power generation – the company's system to address coal ash residue resulting from electricity generation. When new regulations required changes to that system, investor funds were used to modify that system and those modifications were property capitalized as "electric plant utilities." Unlike the facts of *Thornburg*, *Carolina Trace* and *Carolina Water Service*, the investor funds that have been expended (and properly considered by the Commission through deferral accounting) are directly linked to property that was used and useful in rendering services to the public.

Here, the equity and debt investors of Duke Energy have advanced the capital necessary to service the needs of the public. Those investor funds have a direct link to the property that generated electricity for those customers. Accordingly, Duke Energy should be permitted to recoup the costs to investors (including the cost of equity need to advance those funds). *Virginia Elec. & Power Co.*, 285 N.C. at 414-15, 206 S.E.2d at 295-96. The deferment of the Asset Retirement Obligation has resulted in the shareholders of Duke Energy investing $778 million in funds – *i.e.*, property – necessary in providing service to the public. The Utility Commission's decision to award a fair rate of return on this substantial investment by the Company is firmly based in the record and the N.C. Public Utilities Act.

III. THE VAST MAJORITY OF THE COAL ASH COMPLIANCE COSTS WERE LONG-TERM CAPITAL EXPENSES

As discussed in Section II above, the coal ash closure costs were investor-funded, appropriately treated as plant utilities under deferral accounting and therefor stand as property for which a return on investment is appropriate. A separate and independent reason exists to allow a rate of return on these costs. The vast majority of the expenditures stand as long-term assets that constitute capital improvements – aside from the fact that they were properly capitalized as an ARO.

The basin modifications and lined landfills that are the subject of this appeal constitute long-term assets and improvements to real property. These basins are part of the Company's coal ash management system that is directly related to the service provided by the Company – power generation. Throughout its orders, the Commission expressly recognized that the majority of the coal ash closure costs are improvements to real property for which a rate of return is appropriate. (DEC R p 1101). The Commission observed that a significant portion of the coal ash closure costs "has been or will be spent on creation of lined landfills with synthetic liners or impermeable caps over existing impoundments." (*Id.*) Such structures are "are long-lived assets and are capital in nature – not expenses." (*Id.*)

Because these basins are improvements to real property, all of the costs associated with the creation or modification of the basins similarly become part of the capital cost of the new or modified basin. As a result, the construction-related costs are capitalized. Accordingly, when an electric plant or addition is purchased or constructed, many expenses that would otherwise be treated as operating or maintenance costs are actually capital costs because they are associated with the system being built. These costs include contract work, labor, materials and supplies, transportation of employees and equipment, general administration attributable to the construction, engineering services, insurance, legal costs and environmental studies. 18 C.F.R. § 101, Electric Plant Instruction No. 3. Much of construction costs for the coal ash basins fall within these categories, including environmental, health and safety studies associated with the construction, infrastructure costs, landfill construction, engineering closure plans, modification of power plants to accommodate basin modifications, mobilization costs and installation of water treatment systems. (DEC R p 1093; DEP T Vol 6, p 136; DEC Tr Vol 14, p 132; DEC Doc. Ex. 3574-75; *see also* DEP R p 625 (describing plant modifications to accommodate basin modifications); DEC R p 1037 (plant modifications are required "to fully transition to dry ash handling")). Similarly, the construction of rail spurs and the installation of rail handling equipment to serve these basins stand as long-term property that is used and useful for providing electricity to customers. (DEC T Vol. 9, p 125; DEP T Vol 11, pp 146, 234-35; DEC Doc. Exs. 3177, 5081, 5086, 5341-42, 5355, 5358, 10473). The Public Staff's witness (Maness) admits that the closure costs include "design and permits, mobilization, site preparation, site infrastructure, water treatment and management, ash processing, construct a landfill, and cap in place, site restoration, demobilization and closing, capital expenditures related to equipment and facilities." (DEP T Vol 19, pp 57-58). The vast majority of these costs constitute improvements to real property and are therefore capital assets. Thus, not only are these expenses properly treated as "utility plant" under the required accounting procedures for public utilities, these expenditures give rise to long-term assets that benefit the utility's customers.

The landfills, accompanying plant modifications and other expenses to modify the Company's coal ash remediation system, as required by the CCR rules and CAMA, are property "used and useful." A landfill that stores coal ash which is a byproduct of electricity generation stands as a capital expenditure required to provide electricity to the public. Accordingly, these assets are entitled to a rate of return.

Appellants' arguments that the coal ash closure costs do not constitute property used and useful in providing service to the public is not supported by the record. Duke Energy's coal ash closure costs were "expended to comply with the CCR Rule and CAMA" and "the capitalized costs for which the Company seeks recovery are eligible for a return." (DEC R p 1092). The costs are, therefore, "used and useful."

IV. THE COMMISSION PROPERLY REJECTED THE PUBLIC STAFF'S "EQUITABLE SHARING" ARGUMENT

Citing N.C. Gen. Stat. § 62-133(d), the Public Staff argues that the Commission has the discretion to make a downward adjustment in the utility's reasonable operating costs, the utility's "property used and useful," and the rate of return that is determined to be fair. (*See* Public Staff Br. pp 130-43 (referring to its theory as "equitable sharing")). The Public Staff's argument fails for two separate and independent reasons. First, N.C. Gen. Stat. § 62-133(d) does not give the Commission the authority to ignore the detailed provisions of the Public Utilities Act regarding how rates are to be determined. Second, the Commission did not abuse its discretion in failing to adopt the dramatic reductions advocated by the Public Staff.

A. N.C. Gen. Stat. § 62-133(d) Does Not Give the Utilities Commission Unbridled Discretion to Reduce Rates.

N.C. Gen. Stat. § 62-133(d) states: "The Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." The Public Staff does not argue that the Commission excluded material facts of record. In the two rate cases combined, the Commission held 32 days of hearings and considered thousands of pages of exhibits.

The General Assembly's statement that the Commission shall consider all material facts should not be construed as authorizing the Commission to ignore the detailed provisions of the ratemaking formula set by statute. N.C. Gen. Stat. § 62-133(d) must be read in light of the other subsections of this statute. Elsewhere the statute directs that the Commission must follow a specific formula for setting rates for a public utility. N.C. Gen. Stat. § 62-133(b). For example, the section sets out how depreciation is to be accounted for, how a fair rate of return is to be calculated, the length of the test period during which operating expenses are to be determined, how to account for construction work in progress and numerous other factors that must go into the calculation of rates. N.C. Gen. Stat. § 62-133(b), (c).

When the General Assembly delegates legislative authority to an administrative body, such legislation must be "accompanied by adequate guiding standards to govern the exercise of the delegated powers." *Adams v. N.C. Dep't of Natural & Econ. Res*., 295 N.C. 683, 697, 249 S.E.2d 402, 410 (1978). Otherwise, the legislation is unconstitutional as a violation of separations of powers. *Id.* at 696-98, 249 S.E.2d at 410-11. Here, the statutory formula set out in N.C. Gen. Stat. §

62-133(b), (c) provides an adequate guiding standard for the setting of rates by the Commission. If, however, those guiding standards were to be eviscerated by the interpretation advocated by the Public Staff (i.e., if the Commission were authorized to deny a fair rate of return in its unbridled discretion), the statute would raise grave constitutional concerns. Accordingly, this Court should construe N.C. Gen. Stat. § 62-133(d) narrowly rather than undermine the constitutional validity of the Public Utilities Act. *See N.C. State Bd. of Educ. v. State*, 371 N.C. 149, 160, 814 S.E.2d 54, 62 (2018) ("[w]here one of two reasonable constructions will raise a serious constitutional question, the construction which avoids this question should be adopted") (internal quotations omitted; alternation in original).

The plain text of N.C. Gen. Stat. § 62-133(d) merely provides that the Commission should consider "material facts of record." Facts of record that do not bear on the elements of the ratemaking formula or other specific provisions of Public Utilities Act are not material. Here, the Public Staff is unable to cite to a single element of the Public Utilities Act that was not properly considered by the Commission. In short, the Public Staff reads too much into the simple directive: "The Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C. Gen. Stat. § 62-133(d). The Public Staff's reading of N.C. Gen. Stat. § 62-133(d) as providing the Commission carte blanche to do whatever it wants with respect to rates is inconsistent with the Act and should be rejected by this Court.[19]

The Public Staff's "equitable sharing" recommendation was to disallow the Company from recovering 50% of the coal ash closure costs in the DEP rate case (51% in the DEC rate) – even though these costs had already been paid by investors. The Public Staff offered no rationale for selecting its 50% and 51% disallowances. When the Public Staff's witness was examined on the arbitrary nature of the percentage, he simply punted stating that it is "up to the Commission's discretion to determine what [the] sharing should be." (DEP Tr Vol 19, p 69). In the DEC rate case, the Commission explained why the Public Staff's recommendation of a 51% disallowance was arbitrary:

> [T]he concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...." 2018 DEP Rate Order, p. 189.

(DEC R p 1097).

Black's Law Dictionary defines an "arbitrary and capricious" decision as one "without determining principle." *See Tate Terrace Realty Investors, Inc. v.*

---

[19] The corollary to the Public Staff's argument that the Commission, in its discretion, can make a downward adjustment of rates is that the Commission could also make an upward adjustment of rates.

Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851 (1997). The Public Staff's "equitable sharing" recommendation is devoid of any determining principle. If this recommendation had been adopted by the Commission, the Commission would have acted arbitrarily and capriciously by denying the Company a fair rate of return. An illustrative case is *Sanchez v. Town of Beaufort*, 211 N.C. App. 574, 580, 710 S.E.2d 350, 354 (2011), in which the Court held that it was arbitrary and capricious for a municipal body to "cherry pick" a standard without providing any basis of any particular determining principle. In that case, the Beaufort Historic Preservation Commission ("BHPC") attempted to limit the construction of petitioner's home to twenty-four feet in height "without the use of any determining principle from the BHPC guidelines." *Id.* at 582, 710 S.E.2d at 355. Rather, the BHPC members based the standard "on their own personal preferences," with each member providing a manner of re-working the project's construction to comply with a twenty-four-foot height maximum, but none providing a reason as to *why twenty-four feet* when the height "*could be a different number* …." *Id*. at 581, 710 S.E.2d at 355 (emphasis in original). Thus, while the BHPC members could certainly provide a way to arrive at the height maximum, they could not provide a "why" for *that particular* height maximum. Failure to provide a determining principle for the height maximum itself rendered the BHPC's decision arbitrary and capricious. *Id*. at 582, 710 S.E.2d at 355. The Public Staff's recommendation to disallow 50% or 51% of costs without relying on any standard is just as arbitrary as randomly picking a maximum height for homes.

Like the Attorney General (*see* pp. 63-64, above), the Public Staff incorrectly relies on this Court's precedents concerning plants under construction that were abandoned prior to becoming property used and useful. In support of its "equitable sharing" recommendation, the Public Staff relies on *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989) (*Thornburg I*) and *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 484, 490, 385 S.E.2d 463, 466 (1989) (*Thornburg II*). *Thornburg I* addressed the treatment of costs of Shearon Harris Nuclear Units 2-4 following the abandonment of those units. *Thornburg II* addressed recovery of common facilities that exceeded the needs of Harris Unit No. 1 following the abandonment of Units 2-4. The Public Staff's "equitable sharing" argument is inconsistent with its position in other rate cases. Moreover, the cases on which the Public Staff relies do not support this novel theory.

1. The Public Staff's "Equitable Sharing" Argument is a Dramatic Departure From its Position in Other Rate Cases.

One year before the present rate case, the Commission was faced with a request by Dominion North Carolina Power ("Dominion") for a rate increase to cover its extraordinary costs of complying with the CCR Rule and CAMA. Like the present appeal, Dominion requested that these costs be amortized over a five-year period and that Dominion be allowed to recover a rate of return until Dominion had recouped the funds advanced by shareholders. Rather than argue that there should be an "equitable sharing" of these costs between ratepayers and Dominion, the Public Staff stipulated that because Dominion's expenditures had been prudently incurred and were investor-funded, Dominion should be entitled to recover these costs through rates over a five-year period and also receive a rate of return on the unamortized balance. The Commission approved this Stipulation and authorized rates that allowed Dominion to recover these costs, plus a rate of return. Order Approving Rate Increase and Cost Deferrals, Docket No. E-22, Sub 532 (Dec. 22, 2016). The Public Staff's dramatic break from its position in the Dominion case is arbitrary, and the Public Staff offers no explanation as to why the Commission should treat similarly situated utilities differently under virtually identical facts.[20]

In the Dominion rate case, the Public Staff faced a structurally identical cost recovery proposal and agreed that those costs should be recovered over a five-year period with a rate of return. The Public Staff's position was adopted by the Commission and the coal ash basin closure costs were included in rates – to be amortized over a five-year period. In that case, the Public Staff did not recommend any kind of "equitable sharing." Just as "equitable sharing" was not a valid theory in the Dominion rate case, it is not a valid theory here.

[20] Below, the Public Staff witnesses attempted to explain away its dramatically different positions in the Dominion rate case versus the present rate case. DEC Doc. Ex. 20939-20942. Specially, the Public Staff asserted that the violations and the magnitude of the costs were different in these two rate cases. Although Dominion's coal ash basin closure costs attributable to North Carolina ratepayers is much less than Duke Energy's North Carolina costs, the Public Staff ignores the fact that Dominion's service area in North Carolina is much smaller than Duke Energy's. Similarly, the Public Staff incorrectly compares the total number of asserted environmental violations, rather than whether the purported violations caused any of the expenses that the utility is seeking to recover.

2. This Court's Decisions in *Thornburg I & II* Do Not Support "Equitable Sharing."

In *Thornburg I*, this Court considered whether the Commission erred in allowing the utility to recover construction costs associated with abandoned units of the Shearon Harris Plant as operating expenses under N.C. Gen. Stat. § 62-133(b)(3). The Commission allowed these costs to be amortized over a ten-year period but without a return. In doing so, this Court rejected the Attorney General's argument that operating expenses must have a nexus to property used and useful. Under the North Carolina statute, "operating expenses" are not defined. 325 N.C. at 475, 385 S.E.2d at 457. As long as the expenses are "reasonable," the Commission may allow their recovery under N.C. Gen. Stat. § 62-133(b)(3). This Court held that the Commission's conclusion that the cancellation costs may be recovered as operating expenses (without a rate of return) was supported by substantial evidence and not an abuse of discretion.

In *Thornburg I*, this Court expressly rejected the Attorney General's reliance on selected decisions from other States in which abandoned construction costs were disallowed. This Court noted that other States have used three different approaches: (1) allowing the utility to recover all cancellation costs with a rate of return on the unamortized balance; (2) disallowing all costs associated with construction of a plant that is abandoned; and (3) approving recovery of the construction costs associated with an abandoned plant over a period of years but allowing no return on the unamortized balance. With respect to these three approaches, this Court noted, "Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes an equitable sharing of the loss between ratepayers and the utility stockholders." *Id.* at 480, 385 S.E.2d at 460 (internal quotations omitted). The Public Staff glosses over the fact that the Court's statement was made in the context of whether abandoned plant construction costs can be recovered as operating expenses – not whether the North Carolina Public Utilities Act or the U.S. and N.C. Constitutions permit the Commission to deny a fair rate of return on property that *is* used or useful in providing services to customers. In fact, each of the four law review articles cited by this Court in this paragraph of its opinion are specifically addressing construction costs for abandoned plants.[21] *Id.* The Public Staff's attempt to read *Thornburg I* as permitting the Commission to deny a fair rate of return on property that is determined to be used and useful cannot be reconciled with the narrow scope of this Court's holding in *Thornburg I*.

This Court's decision in *Thornburg II* similarly does not permit the Commission to refuse to allow a fair rate of return on property that is used and useful. In *Thornburg II*, the Commission was faced with how to treat the construction costs of common facilities (e.g., a fuel handling building that was larger than needed for

[21] P. Rodgers & C. P. Gray, *State Commission Treatment of Nuclear Plant Cancellation Costs*, 13 Hofstra L. Rev. 443 (Spring 1985); Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plants and Excess Capacity*, 132 U. Pa. L. Rev. 497 (1984); Sommers, *Recovery of Electric Utility Losses from Abandoned Construction Projects*, 8 Wm. Mitchell L. Rev. 363 (1982); Olsen, *Statutes Prohibiting Cost Recovery for Cancelled Nuclear Power Plants: Constitutional? Pro-Consumer?*, 28 Wash. U.J. Urb. & Contemp. L. 345, 377 (1985).

one unit) associated with the Shearon Harris Units that were subsequently abandoned. The Commission allowed the utility to include some – but not all – of these costs in rate base. This Court reversed, concluding that because the Commission had quantified the costs ($570 million) that were attributable to the three cancelled units, the cost of these excessive facilities must be treated as cancellation costs and no portion could be included in rate base. This Court concluded that if the facilities were excessive, they were not "used and useful" and could not be included in rate base. *Id.* at 495, 385 S.E.2d at 469. The result was to allow the utility to recover the $570 million as operating expenses – but without a rate of return.

The Public Staff asserts that *Thornburg II* is an express approval of its "equitable sharing" theory. It is nothing of the kind. *Thornburg II* was a straight-forward application of the rate-making formula. If property is used and useful in providing service to the public, the original cost (less depreciation) goes into rate base. If an expense was prudently incurred but is not property used and useful (e.g., abandoned construction costs or excessive facilities), the costs are recoverable as operating expenses – without a rate of return. Here, unlike *Thornburg I & II*, the capital funded by shareholders was directly incurred as a result of the generation of electricity in service to the public. The language and holding of *Thornburg II* (just like *Thornburg I*) cannot be read as abandoning the precise directives of N.C. Gen. Stat. § 62-133 (which require a return on property used and useful) and allowing the Commission to deny a fair rate of return on capitalized costs that serve the public.

Thornburg I & II involved prudent expenditures that were never put to use in providing service to the public because of the abandonment of the planned units. Unlike *Thornburg I & II*, the investor-funded capitalized costs at issue here were used and useful in responding to regulatory changes and providing electricity to the public. *Thornburg I & II* speak specifically to abandoned plants and excessive facilities – not property that is used and useful. Under the guise of its "equitably sharing" theory, the Public Staff is essentially asking this Court to ignore the precise ratemaking formula set out in the Public Utilities Act.

B. <u>The Commission Did Not Abuse its Discretion in Determining that a Further Downward Adjustment Would Not be Reasonable and Appropriate.</u>

Regardless of whether N.C. Gen. Stat. § 62-133(d) may be read as authorizing the Commission to make a downward adjustment in rates, the Commission declined in these cases to exercise whatever discretion the Public Staff insists it possesses.[22]

---

[22] Accordingly, the Public Staff's argument (*see* Public Staff Br. pp 64-74) that the Commission's decisions are contradictory and therefore in error makes no sense. The Commission's determinations are not contradictory. In both cases the Public Staff asked the Commission to exercise discretion and disallow some portion of Duke Energy's coal ash basin closure costs (even if prudently incurred) through an "equitable sharing" mechanism. In both cases, the Commission declined the invitation. Public Staff has not shown in these appeals that the Commission abused its discretion. Moreover, the Commission declined Public Staff's invitation because it concluded that acceding to the invitation and disallowing 50% (in the case of DEP) or 51% (in the case of DEC) of Duke Energy's cost recovery would result in "rates that would be unjust and unreasonable, while the Commission's charge is to fix rates that are, to the contrary, just and reasonable. G.S. 62-131(a)." DEP R p 675. The Commission is the body charged with setting rates that are just and reasonable. *State ex rel. Utils. Comm'n v. Eddleman*, 320 N.C. 344, 367, 358 S.E.2d 339, 347 (1987) ("The Commission, not the courts, has been given the authority to regulate the rates of public utilities.").

In the DEP rate case, the Commission stated that "in its discretion," it had concluded to allow amortization of the deferred CCR costs "over five years with full return on the unamortized balance" – after a downward adjustment as a "management penalty." (DEP R p 951 (Order on Motion for Clarification); *see also id.* at 668 ("the Commission chooses in its discretion not to adopt [the Public Staff's] recommendation")). In the DEC rate case, the Commission similarly concluded that except for a downward adjustment based on a management penalty, it would not be appropriate to exercise its discretion to make a downward adjustment:

> The Public Staff argues that the approval of a return is discretionary. The Commission determines it unnecessary to determine whether the costs must receive a return on the unamortized balance. In its discretion, as expressly authorized by N.C. Gen. Stat. § 62-133(d), with the exception [of a management penalty,] it approves a return.

(DEC R p 1099). Accordingly, it appears the Public Staff is really seeking some sort of advisory opinion from this Court as to the propriety of its "equitable sharing" position. Of course, this Court is not in the business of providing advisory opinions. *City of Greensboro v. Wall*, 247 N.C. 516, 519, 101 S.E.2d 413, 416 (1958).

Here, the Commission decided to make a downward adjustment (totaling $100 million in the two cases) but concluded not to exercise its discretion to make a further adjustment.[23] The Commission explained why it was not making a further adjustment:

> No witness argues that the Commission lacks the discretion to follow the precedent it established in [early rate cases,] where it addressed the issue of amortizing deferred ARO CCR remediation costs over five years and a return on the unamortized balance. No witness argues that the law forbids the Commission to authorize a return on the unamortized balance. The Commission chooses to exercise its discretion and authority under N.C. Gen. Stat. § 62-133(d) and follow its precedent here – amortize the ARO costs over five years and authorize a return on the unamortized balance…. The Commission will not accept the Public Staff equitable sharing argument primarily because the Commission determines in its discretion that amortization of the deferred ARO costs over 25 years is inequitable …

(DEC R pp 1099-1100).

The Commission's reasoning for rejecting the Public Staff's proposal is set out at length in the Commission's orders. As the Commission explained, rates that do not allow the utility to recoup its reasonable costs would jeopardize the financial strength of the utility – thereby causing ratepayers to pay more for electricity over time and diminish the quality of the services that the utility has the ability to provide. (DEP R p 676). Moreover, failing to allow the Company to recover a fair rate of return on its property (whether on physical plant, working capital, or otherwise supplied by investors) is contrary to the express mandate of the Public Utilities Act

[23] Duke Energy has not appealed from the Commission's downward adjustment in the amount of $100 million ($30 million in the DEP case and $70 million in the DEC case). N.C. Gen. Stat. § 62-133(d) should not be read as giving the Commission discretion to deviate from the formula set forth in the Public Utilities Act. As set above, the parties' disagreement with respect to N.C. Gen. Stat. § 62-133(d) need not be decided here. The Commission exercised its discretion to make an adjustment, but not one of the size requested by the Public Staff. The Commission decision was not arbitrary or capricious.

and the U.S. Supreme Court's precedent with regard to ratemaking. (DEC R pp 857-858). Virtually the entire 334 pages of the majority opinion in the DEC Order and 234 pages of the majority opinion in the DEP Order explain why the circumstances of these cases do not make a further downward adjustment appropriate. Neither the Public Staff nor any other Appellant has been able to articulate why the rates that were set by the Commission are wholly devoid of rationality or reason. *See State v. Hennis,* 323 N.C. 279, 285, 372 S.E.2d 523, 527 (1988) (abuse of discretion occurs when a "ruling is manifestly unsupported by reason or is so arbitrary that it could not have been the result of a reasoned decision"). Because there was no abuse of discretion in the Commission's decision to allow a downward adjustment (but not as large as the Public Staff was requesting), the Public Staff's exception to the Commission's decision fails.

V. THE SIERRA CLUB'S ASSERTION THAT N.C. GEN. STAT. § 62-133.13 BARS THE RECOVERY OF ALL COAL ASH BASIN CLOSURE COSTS IS NOT SUPPORTED BY THE RECORD AND IS CONTRARY TO THE STATUTE

North Carolina General Statutes Section 62-133.13 provides:

> The Commission shall not allow an electric public utility to recover from the retail electric customers of the State costs resulting from an unlawful discharge to the surface waters of the State from a coal combustion residuals surface impoundment, unless the Commission determines the discharge was due to an event of force majeure. … For the purposes of this section, "*unlawful discharge" means a discharge that results in a violation of State or federal surface water quality standards*.

(Emphasis added). Although the Attorney General argued to the Utilities Commission that this statutory provision should bar a portion of the coal ash basin closure costs and includes an exception to this effect in his Notice of Appeal, the Attorney General has abandoned this claim and makes no such argument in his brief to this Court. (*See* DEC R p 1048). The Sierra Club stands as the sole Appellant who is asserting that the Commission's Order includes items that should have been excluded under N.C. Gen. Stat. § 62-133.13.

For N.C. Gen. Stat. § 62-133.13 to be applicable, there must be a discharge from a surface water impoundment that results in a violation of state or federal <u>surface</u> water quality standards. The discharge must also have occurred on or after 1 January 2014. 2014 N.C. Sess. Laws 122. Moreover, the costs must <u>result from</u> an unlawful discharge.

The Sierra Club argues that the coal ash basin impoundments at some plants had seeps and that these seeps would have entered surface waters in small or minute quantities. *See* North American Dictionary (defining "seep" as a "flow or leak slowly through porous material or small holes"). The Sierra Club proceeds to argue that the steps Duke Energy took to address the new CCR Rule and CAMA involved dewatering the coal ash ponds and removal of the ash. Because these steps also abated the seeps, the Sierra Club contends that all of these costs should be viewed as resulting from an unlawful discharge. (Sierra Club Br. pp 18-21).

The Sierra Club's reading of the statute is unreasonable. Under the plain language of the statute, when a utility causes an unlawful discharge to state or federal surface waters that results in a violation of the applicable water quality standards, the response costs are not recoverable. That was precisely the situation at Dan River.

Customers did not bear any of the costs of the cleanup of the Dan River – a commitment that Duke Energy made to its customers even before the enactment of N.C. Gen. Stat. § 62-133.13. All of the costs from the Dan River spill were paid by shareholders. The General Assembly, however, did not intend that a seep (that could be addressed through trenching, diking or similar steps) would preclude a utility from recovering the costs of closing a coal ash basin in order to comply with the CCR Rule and CAMA. If this had been the General Assembly's intent, it would have undoubtedly stated this expressly.

The Commission concluded that the coal ash basin closure costs resulted from the adoption of CCR rules and CAMA. (DEC R p 1092). This conclusion is supported by substantial evidence and is detailed throughout the Commission's decision. (DEC R p 1037; DEC T Vol 14, pp 100-01, 115). Moreover, the Commission went to great lengths to identify expenditures resulting from seeps that were alleged to have resulted in water quality issues. Such expenditures that were "independent of the requirements of the CCR Rule and CAMA" were expressly disallowed. (DEC R p 1046). Except for these disallowances, no seepage caused Duke Energy to incur any "unjustified costs to comply with current laws and regulations. (*Id.* at 1092).

The Commission diligently applied the requirements of N.C. Gen. Stat. § 62-133.13. Its conclusions and findings are set out in detail in its orders. The Commission's findings in this regard are supported by substantial evidence. The

Sierra Club's reading of N.C. Gen. Stat. § 62-133.13 should be rejected by this Court.

VI. TO THE EXTENT THAT THE ATTORNEY GENERAL CONTINUES TO ARGUE THAT DUKE ENERGY CAUSED THE ENACTMENT OF CAMA AND THEREFORE SHOULD NOT BE ALLOWED TO RECOVER ANY COAL ASH BASIN CLOSURE COSTS, THIS THEORY LACKS MERIT

Both the Attorney General and the Sierra Club assert that CAMA was enacted in response to the spill at Dan River. (AG Br. pp 51, 58; Sierra Club Br. p 21). Before the Commission, the Attorney General argued that CAMA was enacted as a result of the Dan River spill and that Duke Energy could therefore not recover any cost to comply with CAMA – even if those costs do not relate to the release of coal ash from the Dan River Steam Plant (which are not being requested by the Company). A witness presented by the Attorney General, for example, opined that Duke Energy's actions caused the enactment of CAMA and consequently any costs to comply with CAMA (over and above the costs to comply with the CCR Rule) should be disallowed. (DEC T Vol 11, pp 239, 248-50, 272).

On appeal, the Attorney General discusses the Dan River spill at length and then asserts that this incident contributed to the enactment of CAMA and therefore increased Duke Energy's coal ash basin closure costs. (AG Br. p 60). Despite the 17 pages of his brief that the Attorney General devotes to discussing the Dan River spill, the Attorney General fails to appreciate the fact that Duke Energy is not seeking to recover any costs associated with the Dan River spill. (AG Br. pp 26-35, 37, 50-51, 58, 60, 64-65; *see* DEC R p 850). Similarly, the considerations that came into play in enacting CAMA are irrelevant to this rate case. In North Carolina, legislative intent can only be determined from the legislation itself – not the statement of legislators, committee reports or statements made on the floor of the General Assembly. *See Elec. Supply Co. of Durham v. Swain Elec. Co.*, 328 N.C. 651, 657, 403 S.E.2d 291, 295 (1991); *Styres v. Phillips*, 277 N.C. 460, 472, 178 S.E.2d 583, 590 (1971). Consequently, the issue that was before the Commission (and that should be the focus of the Attorney General's brief) is whether the costs at issue were prudently incurred in responding to the CCR Rule and CAMA.[24] Testimony that the Dan River spill caused the enactment of CAMA has no more bearing on the Company's ability to recover coal ash compliance costs than testimony that Duke Energy supported the N.C. Clean Smokestack Act (thereby leading to its enactment) would have had when Duke Energy sought recovery of the costs of complying with that Act.

The expenditures that the Company made to comply with the CCR Rule and CAMA are well-documented and were thoroughly considered by the Commission. Despite the voluminous evidence presented by the Company concerning its costs, the Attorney General and the other Appellants were not able to identify any costs that were not prudently incurred. To the extent that the Attorney General is

[24] In any event the Commission did not ignore Appellants' "Duke caused CAMA" argument. The Commission in fact incorporated any responsibility that might be assigned to Duke Energy for CAMA's enactment into its management penalty. DEC R p 1143; DEP R p 682.

continuing to assert that Duke Energy cannot recover costs to comply with CAMA, that position finds no support in the Public Utilities Act or this Court's precedents.

CONCLUSION

For the reasons set forth herein, the 2018 DEP Rate Order and the 2018 DEC Rate Order should be affirmed in all respects.

Respectfully submitted, this 25th day of September, 2019.

/s/ Kiran H. Mehta
Kiran H. Mehta
N.C. State Bar No. 11011
Troutman Sanders LLP
301 S. College Street, Suite 3400
Charlotte, NC 28202
Telephone: (704) 998.4072
Email: kiran.mehta@troutman.com

N.C. R. App. P. 33(b) Certification: I certify that all of the attorneys listed below have authorized me to list their names on this document as if they had personally signed it.

Christopher G. Browning, Jr.
NC State Bar No. 13436
Troutman Sanders LLP
305 Church at North Hills Street, Suite 1200
Raleigh, NC 27609
Telephone: (919) 835.4127
Email: chris.browning@troutman.com

Molly McIntosh Jagannathan
N.C. State Bar No. 36931
Troutman Sanders LLP
301 S. College Street, Suite 3400
Charlotte, NC 28202
Telephone: (704) 998.4074
Email: molly.jagannathan@troutman.com

Attorneys for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing JOINT BRIEF OF APPELLEES DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC on all parties to the appeal by e-mail in accordance with Rule 26 of the North Carolina Rules of Appellate Procedure.

This 25th day of September, 2019.

/s/ Kiran H. Mehta
Kiran H. Mehta

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

			North Carolina Retail Operations				
Line No.	**Description**	**Total Company Per Books** (a) **(Col. 1)**	**Per Books (Col. 2)**	**Accounting Adjustments** (c) **(Col. 3)**	**Before Proposed Increase (Col. 4)**	**Revenue and Expenses from Proposed Increase** (e) **(Col. 5)**	**After Proposed Increase (Col. 6)**
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (296,495)	$ 3,361,009	$ 412,805	$ 3,773,814
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(29,989)	851,653		851,653
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(189,938)	860,881	1,524	862,406
5	Depreciation and amortization	1,060,260	669,787	242,494	912,282		912,282
6	General taxes	153,362	102,197	1,412	103,609		103,609
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	EDIT Amortization	-	-	(30,548)	(30,548)	-	(30,548)
9	Net income taxes	150,622	112,986	(46,377)	66,610	95,056	161,666
10	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
11	Total electric operating expenses	4,736,071	2,982,032	(56,390)	2,925,642	96,581	3,022,223
12	Operating income	$ 946,351	$ 675,472	$ (240,104)	$ 435,367	$ 316,224	$ 751,591
13	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 259,622 (d)	$ 10,118,673	$ 52,407 (f)	$ 10,171,080
14	Rate of return on North Carolina retail rate base		6.85%		4.30%		7.39%

-- Some totals may not foot or compute due to rounding.

Notes:
(a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

					North Carolina Retail Operations					
					Before Proposed Increase			After Proposed Increase		
Line No.	Description		Dec. 31, 2018 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt		$ 8,108,191	47.00%	$ 4,755,776	4.11%	$ 195,340	$ 4,780,408	4.11%	$ 196,352
2	Members' equity	(a)	8,717,931	53.00%	5,362,897	4.48%	240,027	5,390,672	10.30%	555,239
3	Total		$ 16,826,122	100.00%	$ 10,118,673 (b)		$ 435,367 (c)	$ 10,171,080 (b)		751,591
4	Operating income before increase (Line 3, Column 5)									435,367
5	Additional operating income required (Line 3 minus Line 4)									316,224
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue									(234)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)									96,815
8	Additional revenue requirement									$ 412,805
9	Revenue Adjustments	(d)								$ (91,232)
10	Net Increase									$ 321,573

-- Some totals may not foot or compute due to rounding.

Notes: (a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	-	(52,114)	-	(172,813)
1(D)		Annualize retail revenues for current rates- Supplemental	24,093	-	-	89	-	-	-	5,562	-	18,443
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	-	3,304	-	10,955
2(F)		Update fuel costs to proposed rate- Rebuttal	-	24,010	-	-	1,684	-	-	(5,953)	-	(19,741)
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	-	(13,653)	-	(45,273)
3(E)		Normalize for weather- Supplemental	4,882	(2,252)	-	18	-	-	-	1,649	-	5,467
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	-	534	-	1,771
4(E)		Annualize revenues for customer growth- Supplemental	(7,341)	(5,328)	-	(27)	-	-	-	(460)	-	(1,526)
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	-	63,161	-	128,547
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	(31)	-	-	-	7	-	24
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	-	556	-	1,843
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	(161)	-	-	-	37	-	124
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	-	(9,747)	(1,481)	(30,841)
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	(661)	-	-	153	-	508
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	-	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	-	(17,857)	-	(59,213)
10(G)		Adjust for post test year additions to plant in service- Partial Settlement	-	-	-	-	(7,643)	(1,566)	-	2,134	-	7,076
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	-	(24,553)	-	(81,419)
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	-	(9,949)	-	-	2,305	-	7,644
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	-	(304)	-	(1,007)
12(G)		Annualize O&M non-labor expenses- Partial Settlement	-	-	-	2,882	-	-	-	(668)	-	(2,214)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	-	4,542	-	15,060
13(G)		Normalize O&M labor expenses- Partial Settlement	-	-	-	(5,198)	-	(72)	-	1,221	-	4,049
14		Update benefits costs	-	-	-	(3,060)	-	-	-	709	-	2,351
14(D)		Update benefits costs- Supplemental	-	-	-	(3,298)	-	-	-	764	-	2,534
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	-	1,444	-	4,788
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	42	-	-	-	(10)	-	(32)
16	*	Amortize rate case costs	-	-	-	701	-	-	-	(162)	-	(539)
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	-	341	-	1,129
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	(205)	-	-	-	47	-	157

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Partial Settlement

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	-	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	-	988	-	3,276
19(E)		Adjust for Merger Related Costs	-	-	-	-	(10)	-	-	2	-	8
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	-	5,414	-	17,952
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(774)	-	-	-	179	-	594
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	(2,183)	-	2,183
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	123	-	(123)
22(G)		Synchronize interest expense with end of period rate base- Partial Settlement	-	-	-	-	-	-	-	3,581	-	(3,581)
23	*	Adjust cash working capital	-	-	-	-	-	-	-	122	-	(122)
23(G)		Adjust cash working capital- Partial Settlement	-	-	-	-	-	-	-	(45)	-	45
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-	-
24(C)		Adjust coal inventory- Supplemental	-	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	-	(1,204)	-	(3,993)
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	72	-	-	-	(17)	-	(55)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	-	(20,760)	-	(68,841)
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	(873)	-	-	202	-	671
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	-	21	-	70
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	(1,826)	-	-	423	-	1,403
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	-	(10,129)	-	(33,588)
29(G)		Update deferred balance and amortize storm costs- Partial Settlement	-	-	-	-	(45,353)	-	-	10,508	-	34,845
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	-	1,767	-	5,859
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	-	-	-	-	10,381	1,032	-	(2,644)	-	(8,769)
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	-	(1,144)	-	(3,794)
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	(4,939)	-	-	-	1,144	-	3,794
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	-	(4,565)	-	(15,138)
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	-	(7,568)	(4,624)	-	-	2,825	-	9,367

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Partial Settlement

Line No.	Description	Electric Operating Revenue	Fuel Used in Electric Generation	Purchased Power and Net Interchange	Wages Benefits Materials Etc.	Depreciation and Amortization	General Taxes	EDIT 0.0000%	Income Taxes 23.1693%	Amortization of ITC	Operating Income
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	-	455	-	1,510
36(E)	Correct Lead Lag- Supplemental	-	-	-	-	-	-	-	-	-	-
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	-	-	-	(30,548)	7,078	-	23,470
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	(2,834)	-	-	-	657	-	2,177
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	9,300	-	-	-	(2,155)	-	(7,145)
40	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ -	$ (74,904)	$ (1,481)	$ (319,441)
40(G)	Change from Application	21,635	16,430	-	(12,632)	(58,874)	(606)	(30,548)	28,528	-	79,336
41	Total adjustments	$ (296,495)	$ (29,989)	$ (1,965)	$ (189,938)	$ 242,494	$ 1,412	$ (30,548)	$ (46,377)	$ (1,481)	$ (240,104)

-- Some totals may not foot or compute due to rounding.
Notes: * Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Partial Settlement

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	225,760	-	225,760
1(D)		Annualize retail revenues for current rates- Supplemental	-	-	-	-	-	-	-	-	(24,093)	-	(24,093)
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,311)	-	(14,311)
2(F)		Update fuel costs to proposed rate- Rebuttal	-	-	-	-	-	-	-	-	25,789	-	25,789
3	*	Normalize for weather	-	-	-	-	-	-	-	-	59,144	-	59,144
3(E)		Normalize for weather- Supplemental	-	-	-	-	-	-	-	-	(7,142)	-	(7,142)
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,314)	-	(2,314)
4(E)		Annualize revenues for customer growth- Supplemental	-	-	-	-	-	-	-	-	1,993	-	1,993
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,869)	-	(11,869)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,932)	(94,010)	(261,943)
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	-	-	-	-	-	(31)	230	199
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,408)	-	(2,408)
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	-	-	-	-	-	(162)	-	(162)
8		Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,290	-	40,290
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	-	-	-	-	(663)	-	(663)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,079	-	4,079
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,355	120,182	197,537
10(G)		Adjust for post test year additions to plant in service- Partial Settlement	(387,296)	255,631	-	20,220	(25,293)	-	-	(136,738)	(9,244)	(12,649)	(21,893)
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	106,364	29,499	135,863
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,986)	(2,835)	(12,820)
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,316	-	1,316
12(G)		Annualize O&M non-labor expenses- Partial Settlement	-	-	-	-	-	-	-	-	2,892	-	2,892
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,674)	-	(19,674)
13(G)		Normalize O&M labor expenses- Partial Settlement	-	-	-	-	-	-	-	-	(5,290)	-	(5,290)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,071)	-	(3,071)
14(D)		Update benefits costs- Supplemental	-	-	-	-	-	-	-	-	(3,310)	-	(3,310)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,255)	-	(6,255)
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	-	-	-	-	-	42	-	42
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	704	186	889
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	(2,670)	619	-	-	(2,051)	-	(186)	(186)
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,475)	-	(1,475)
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	-	-	-	-	-	(206)	-	(206)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Partial Settlement

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,878)	(5,821)	(7,699)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,280)	31	(4,248)
19(E)		Adjust for Merger Related Costs	(460)	9	-	-	-	-	-	(451)	(10)	(41)	(51)
20	*	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,453)	1,621	(21,832)
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(23,297)	5,398	-	-	(17,899)	(777)	(1,621)	(2,398)
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,851)	-	(2,851)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22(G)		Synchronize interest expense with end of period rate base- Partial Settlement	-	-	-	-	-	-	-	-	4,678	-	4,678
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	160	(2,447)	(2,287)
23(G)		Adjust cash working capital- Partial Settlement	-	-	-	9,699	-	-	-	9,699	(58)	882	824
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24(C)		Adjust coal inventory- Supplemental	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,922)	(1,922)
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,217	-	5,217
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	-	-	-	-	-	72	-	72
26		Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,933	(8,037)	81,896
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	-	-	-	-	(876)	20	(857)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,779	-	5,779
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	-	-	-	-	(1,833)	-	(1,833)
29	*	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,879	42,594	86,473
29(G)		Update deferred balance and amortize storm costs- Partial Settlement	(68,248)	1,812	-	(612,045)	141,807	-	-	(536,674)	(45,521)	(48,597)	(94,118)
30		Adjust other revenue	-	-	-	-	-	-	-	-	4,165	-	4,165
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(235)	-	(235)
32	*	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,654)	(2,965)	(10,619)
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,456	6,809	18,265
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,957	-	4,957
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	-	-	-	-	-	(4,957)	-	(4,957)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,776	2,230	22,006
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	(248)	(27,188)	6,299	-	-	(21,136)	(12,237)	(1,915)	(14,152)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Partial Settlement

Line No.	Description	EPIS	Accum Deprec	Materials & Supplies	Working Capital	ADIT	Operating Reserves	CWIP	Rate Base	Oper Inc Rev Req Impact	R/B Rev Req Impact	Total Rev Req Impact
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,972)	-	(1,972)
36(E)	Correct Lead Lag- Supplemental	-	-	-	(8,580)	-	-	-	(8,580)	-	(775)	(775)
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	30,548	(7,078)	-	-	23,470	(30,661)	2,121	(28,540)
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	-	-	-	-	-	(2,844)	-	(2,844)
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	-	-	-	-	-	9,334	-	9,334
40	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 417,313	$ 83,718	$ 501,031
40(G)	Change from Application	(168,951)	46,780	(21,565)	(654,448)	131,282	-	-	(666,901)	(103,644)	(60,259)	(163,903)
41	Total adjustments	$ 411,607	$ (55,668)	$ (172,644)	$ 237,259	$ (58,002)	$ -	$ (102,930)	$ 259,622	$ 313,669	$ 23,459	$ 337,128

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 411,607	$ 19,217,518
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(55,668)	(8,097,727)
3	Net electric plant		16,126,825	10,763,851	355,939	11,119,790
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	237,259	(137,913)
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(58,002)	(1,390,630)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 259,622	$ 10,118,673

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (148,421)	$ 9,908,098
2	Transmission Plant	2,746,389	1,643,263	156,091	1,799,354
3	Distribution Plant	6,944,764	6,052,263	337,439	6,389,702
4	General Plant	628,616	465,435	44,402	509,837
5	Intangible Plant	527,370	358,178	49,459	407,638
6	Subtotal	27,398,830	18,575,658	438,970	19,014,629
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 411,607	$ 19,217,518

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	North Carolina Retail Operations: Accounting Adjustments (Col. 3)	North Carolina Retail Operations: As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (19,814)	$ (4,410,572)
2	Transmission Reserve	(816,198)	(488,611)	(26,075)	(514,686)
3	Distribution Reserve	(3,235,148)	(2,819,386)	29,405	(2,789,981)
4	General Reserve	(167,536)	(124,045)	(16,245)	(140,291)
5	Intangible Reserve	(322,831)	(219,260)	(22,938)	(242,198)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (55,668)	$ (8,097,727)
7	The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:				
8	Steam production plant	0.00%			
9	Nuclear production plant	0.00%			
10	Hydro production plant	0.00%			
11	Other production plant	2.61%			
12	Transmission plant	5.18%			
13	Distribution plant	1.90%			
14	General plant	Various			
15	Intangible plant	20.00%			

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

Smith Exhibit 1
Partial Settlement

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(25,895)	(b)	134,246	52,407	(c)	186,654
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		263,154		(174,137)	-		(174,137)
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		237,259		(21,325)	52,407		31,083
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 237,259		$ (137,913)	$ 52,407		$ (85,505)

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Partial Settlement

Smith Exhibit 1 Supplemental Rebuttal

Line No.	Description	Ref #	SUMMARY OF PROPOSED REVENUE		
			Application	Partial Settlement	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(96,523)	(96,523)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(173,156)	(173,156)
6	Net Revenue Increase		$ 463,619	$ 321,573	$ 321,573
7					

Line No.	Description	Ref #	CHANGE IN OP INCOME				CHANGE IN RATE BASE		
8			Application	Partial Settlement	Total Adjs [1]		Application	Partial Settlement	Total Change [2]
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ (154,370)		$ -	$ -	$ -
11	Update fuel costs to proposed rate	NC-0200	10,955	-	(8,786)		-	-	-
12	Normalize for weather	NC-0300	(45,273)	-	(39,806)		-	-	-
13	Annualize revenues for customer growth	NC-0400	1,771	-	246		-	-	-
14	Eliminate unbilled revenues	NC-0500	9,086	-	9,086		-	-	-
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	128,571		(1,037,885)	-	(1,037,885)
16	Adjust O&M for executive compensation	NC-0700	1,843	124	1,967		-	-	-
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	(30,333)		-	-	-
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	(3,122)		-	-	-
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	(9)	(52,138)		1,326,826	(1,507)	1,190,089
20	Amortize deferred environmental costs	NC-1100	(81,419)	-	(73,775)		325,675	-	295,100
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	37	(3,221)		-	-	-
22	Normalize O&M labor expenses	NC-1300	15,060	3,009	19,109		-	-	-
23	Update benefits costs	NC-1400	2,351	-	4,885		-	-	-
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	4,756		-	-	-
25	Amortize rate case costs	NC-1600	(539)	-	(539)		2,051	(2,051)	-
26	Adjust aviation expenses	NC-1700	1,129	157	1,287		-	-	-
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	1,438		(64,423)	-	(64,423)
28	Adjust for Merger Related Costs	NC-1900	3,276	-	3,284		347	-	(104)
29	Amortize Severance Costs	NC-2000	17,952	-	18,547		17,899	(16,717)	-
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	2,183		-	-	-
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(2,433)	(3,704)		-	-	-
32	Adjust cash working capital	NC-2300	(122)	17	(77)		(27,013)	3,904	(17,314)
33	Adjust coal inventory	NC-2400	-	-	-		9,641	-	(11,603)
34	Adjust for credit card fees	NC-2500	(3,993)	-	(4,048)		-	-	-
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	(68,170)		(88,728)	-	(88,728)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	(4,424)		-	-	-
37	Adjust reserve for end of life nuclear costs	NC-2800	70	1,403	1,473		-	-	-
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	34,448	1,257		470,238	(531,121)	(66,435)
39	Adjust other revenue	NC-3000	(3,188)	-	(3,188)		-	-	-
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	180		-	-	-
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	-	(2,910)		(32,730)	-	42,550
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-		-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	4,299	(5,771)		24,624	(16,124)	3,488
44	Adjust Purchased Power	NC-3500	1,510	-	1,510		-	-	-
45	Correct Lead Lag	NC-3600	-	-	-		-	-	(8,580)
46	Amortize Prot EDIT	NC-3700	-	23,470	23,470		-	23,470	23,470
47	Remove certain Settlement Items	NC-3800	-	2,177	2,177		-	-	-
48	Normalize for storm costs	NC-3900	-	(7,145)	(7,145)		-	-	-
49									
50		Adjustments	$ (319,441)	$ 59,554	$ (240,104)		$ 926,524	$ (540,146)	$ 259,622
51									
52	Operating income	[3]	675,472	675,472	675,472	Rate base [4]	9,859,050	9,859,050	9,859,050
53	Total Adjustments		(319,441)	(240,104)	(240,104)	Total Adjustments	926,524	259,622	259,622
54	Adjusted Net Operating Income		356,031	435,367	435,367	Adjusted Rate Base	10,785,574	10,118,673	10,118,673
55									
56	Revenue Requirement Impact		417,313	(77,801)	313,669	9.0357%	83,718	(48,806)	23,459
			417,313	313,669	313,669		83,718	23,459	23,459

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

Smith Exhibit 2
Partial Settlement

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	NC RETAIL	Reference
1	Additional base revenue requirement	$ 412,805	Smith Partial Settlement Exhibit 1
2	REVISED Annual EDIT Rider 1	7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback	(96,523)	Smith Partial Settlement Exhibit 4
4	Regulatory Asset and Liability Rider	(2,091)	Smith Exhibit 5
5	Subtotal	(91,232)	Sum L3 - L17
6	Net Revenue Increase	$ 321,573	

Smith Exhibit 3
Partial Settlement

DUKE ENERGY PROGRESS, LLC
Reconciliation of Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Item	Amount
1	Revenue requirement increase per Company application	**585,961**
2	Revenue impact of Company supplemental adjustments	(51,617)
3	Revenue impact of Company rebuttal adjustments	9,918
4	Revenue requirement increase per Company Rebuttal Filing	**$ 544,262**
5		
6	Settled issues:	
7	Adjust to remove storm deferral	(92,994)
8	Adjust to normalize storm costs	9,334
9	Adjust executive compensation	(162)
10	Adjust rate case expense	(185)
11	Adjust aviation expenses	(206)
12	Adjust incentives	(3,931)
13	Adjust sponsorships and donations	(23)
14	Adjust for severance costs	(1,511)
15	Adjust lobbying expense	(1,494)
16	Adjust Board of Directors expense	(1,283)
17	Adjust W. Asheville Vanderbilt 115kV Project	(125)
18	Adjust payment card fees	-
19	Adjust outside services	(32)
20	Adjust inflation to February 29, 2020 for settled items	(48)
21	Adjust EOL nuclear materials & supplies reserve expense	(1,833)
22	Adjust Asheville CC deferral	(1,529)
23	Adjust Asheville production displacement	(4,087)
24	Adjust Asheville CC Plant in Service	(1,457)
25	Include flowback of Protected Federal EDIT due to Tax Cuts and Jobs Act	(28,540)
26	Adjust to remove CertainTeed payment obligation	-
27	Adjustments for Settled items	$ (130,106)
28		
29	Unsettled issues:	
30	Change in equity ratio from 53.00% to 50.00% equity	-
31	Change in return on equity from 10.30% to 9.00%	-
32	Adjust for cost of service reallocations - SWP&A	-
33	Update plant and accumulated depreciation to February 29, 2020	-
34	Update revenues, customer growth, and weather to February 29, 2020	-
35	Remove Unprotected Federal, State EDIT, and deferred Federal from base rates for treatment as a rider	-
36	Adjust depreciation rates	-
37	Adjust deferred environmental costs	-
38	Adjust deferred non-ARO environmental costs	-
39	Adjust nuclear decommissioning expense	-
40	Adjust cash working capital under present rates	330
41	Adjust cash working capital under proposed rates	(4,850)
42	Adjust synchronized interest expense	3,179
43	Adjustments for Unsettled items	$ (1,341)
44		
45	Total Revenue impact of adjustments	**$ (131,447)**
46		
47	Revenue Requirement per Smith Partial Settlement Exhibit 1	**$ 412,805**

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

SMITH
Exhibit No. 4
Partial Settlement

			Federal EDIT - Unprotected, PP&E related NC Retail	Federal EDIT - Unprotected, non PP&E related NC Retail	NC EDIT NC Retail	Deferred Revenue NC Retail	Total NC Retail
			(A)	(B)	(C)	(D)	(E)
1	Regulatory Federal EDIT liabilIty including gross up on the books as of 12/31/2018, based on 2017 tax returns	[1]	$ (326,704)	$ 4,862	$ (23,726)		(345,568)
2	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2018-12/31/2018	[1]		$ (30,548)	$ -		(30,548)
3	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2019-8/31/2020	[1]		$ (50,913)	$ -		(50,913)
4	Regulatory Federal EDIT liability including gross up and transition of Protected to Unprotected Regulatory liability as o 8/31/2020 (Sum of L1 to L3)	[1]	$ (326,704)	$ (76,598)	$ (23,726)	$ -	(427,028)
5	Adjustment to implement ASU 2018-02	[1]		$ (34)	$ -		(34)
6	Adjustment for Amended 2017 Federal Return	[1]	$ (415)				(415)
7	Deferred revenues related to 2017 Federal Tax Rate Change as of 12/31/2018	[1]				$ (108,392)	(108,392)
8	Other projected updates through 2/29/2020	[2]			$ (271)	$ (1,923)	(2,194)
9	Regulatory liabilIty for federal tax change including gross up for NC Retail, for Year 1 rider calculation (Sum of L4 to L8)		$ (327,119)	$ (76,631)	$ (23,998)	$ (110,315)	(538,063)
10	Years of rider amortization		20	5	5	2	
11	Annual amortization amount (L9 / L10)		$ (16,356)	$ (15,326)	$ (4,800)	$ (55,157)	(91,639)

[1] Excess deferred tax liability (EDIT) as of 12/31/2018 by jurisdiction, and forecast transition to new rates effective date between categories based on Tax analysis of ADIT.
Federal EDIT related to the federal tax changes booked to the 0254036 and 0254038 accounts is included in other Working Capital in the per books cost of service.
NC EDIT related to the NC state tax reduction deferred to the 0254150 account not included for recovery in NC EDIT rider approved in prior DEP NC rate case.
This NC EDIT is included in other Working Capital in the per books cost of service.
Revenues deferred for federal tax changes with accrued returns in the 0229010 account, are currently excluded from rate base in the per books COSS.

[2] Projected updates to the Federal and NC tax EDIT during 2019 by Tax
NORTH CAROLINA RETAIL, Page 3, Line return accruals on deferred revenues in the 0229010 account projected through 2/29/2020.

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Smith Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	47.00%	4.11%	1.48%
Equity	53.00%	10.30%	5.46%
			6.94%
Statutory Tax Rate			23.17%
Retention factor for NCUC Fee, Uncollectibles			99.63%

Annual Rider Calculation

Year		Beginning Balance, Page 1, L9 (A)	Amortization - From Page 1, L: Federal EDIT - Unprotected, PP&E related (B)	Federal EDIT - Unprotected, non PP&E related (C)	NC EDIT (D)	Deferred Revenue (E)	Total Amortization (F) =(B)+(C)+(D)+[E]	Ending Balance before Return (G) = (A) - (F)	Average of Beginning and Ending Balance (H) = ((A) + (G)) /2	EDIT Balance in Base Rates, Page 1, L1 (I)	Change in Regulatory Liability for Rider Return (J) = (H) - (I)	Return for Rider (K) = (J) x After Tax WACC	Rider Revenues (L) = (F) + (K)	Rider Revenues NCUC Fee, Uncollectibles (M) = (L) / Retention Factor
Sep 20- Nov 21	1	(538,063)	(16,356)	(15,326)	(4,800)	(55,157)	(91,639)	(446,424)	($492,243)	(427,028)	($65,215)	($4,527)	(96,166)	(96,523)
Dec 21- Nov 22	2	(446,424)	(16,356)	(15,326)	(4,800)	(55,157)	(91,639)	(354,784)	($400,604)	(427,028)	$26,424	$1,834	(89,805)	(90,137) [1]
Dec 22- Nov 23	3	(354,784)	(16,356)	(15,326)	(4,800)	-	(36,482)	(318,303)	($336,544)	(427,028)	$90,485	$6,282	(30,200)	(30,312) [1]
Dec 23- Nov 24	4	(318,303)	(16,356)	(15,326)	(4,800)	-	(36,482)	(281,821)	($300,062)	(427,028)	$126,966	$8,814	(27,667)	(27,770) [1]
Dec 24- Nov 25	5	(281,821)	(16,356)	(15,326)	(4,800)	-	(36,482)	(245,339)	($263,580)	(427,028)	$163,448	$11,347	(25,135)	(25,228) [1]

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by September 30th for Commission approv

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL

SMITH
Exhibit No. 4
Partial Settlement

	Deferred Revenue for Federal Tax Rate Change in account 0229010	NC Retail
1	Projected Changes in Deferred Revenue for Federal Tax Rate Change through Feb 2020	($1,923,073)

I/A

Smith Exhibit 1
Second Supplemental

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (a) (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (304,779)	$ 3,352,725	$ 438,211	$ 3,790,936
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(34,636)	847,006		847,006
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(187,341)	863,478	1,618	865,096
5	Depreciation and amortization	1,060,260	669,787	247,926	917,713		917,713
6	General taxes	153,362	102,197	2,381	104,578		104,578
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	EDIT Amortization	-	-	(30,548)	(30,548)	-	(30,548)
9	Net income taxes	150,622	112,986	(49,917)	63,069	100,907	163,976
10	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
11	Total electric operating expenses	4,736,071	2,982,032	(55,580)	2,926,452	102,525	3,028,976
12	Operating income	$ 946,351	$ 675,472	$ (249,198)	$ 426,273	$ 335,686	$ 761,960
13	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 396,705 (d)	$ 10,255,755	$ 55,637 (f)	$ 10,311,392
14	Rate of return on North Carolina retail rate base		6.85%		4.16%		7.39%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

I/A

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

				North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
Line No.	Description	Dec. 31, 2018 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	$ 8,108,191	47.00%	$ 4,820,205	4.11%	$ 197,987	$ 4,846,354	4.11%	$ 199,061
2	Members' equity (a)	8,717,931	53.00%	5,435,550	4.20%	228,287	5,465,038	10.30%	562,899
3	Total	$ 16,826,122	100.00%	$ 10,255,755 (b)		$ 426,273 (c)	$ 10,311,392 (b)		761,960
4	Operating income before increase (Line 3, Column 5)								426,273
5	Additional operating income required (Line 3 minus Line 4)								335,686
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								(249)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)								102,774
8	Additional revenue requirement								$ 438,211
9	Revenue Adjustments (d)								$ (80,096)
10	Net Increase								$ 358,116

-- Some totals may not foot or compute due to rounding.

Notes:
(a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	-	(52,114)	-	(172,813)
1(D)		Annualize retail revenues for current rates- Supplemental	24,093	-	-	89	-	-	-	5,562	-	18,443
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	-	3,304	-	10,955
2(F)		Update fuel costs to proposed rate- Rebuttal	-	24,010	-	-	1,684	-	-	(5,953)	-	(19,741)
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	-	(13,653)	-	(45,273)
11(E)		Normalize for weather- Supplemental	4,882	(2,252)	-	18	-	-	-	1,649	-	5,467
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	-	534	-	1,771
4(I)		Annualize revenues for customer growth- Second Supplemental	(15,625)	(9,976)	-	(58)	-	-	-	(1,296)	-	(4,296)
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	-	63,161	-	128,547
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	(31)	-	-	-	7	-	24
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	-	556	-	1,843
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	(161)	-	-	-	37	-	124
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	-	(9,747)	(1,481)	(30,841)
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	(661)	-	-	153	-	508
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	-	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	-	(17,857)	-	(59,213)
10(I)		Adjust for post test year additions to plant in service- Second Supplemental	-	-	-	-	(2,200)	(850)	-	707	-	2,344
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	-	(24,553)	-	(81,419)
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	-	(9,949)	-	-	2,305	-	7,644
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	-	(304)	-	(1,007)
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	1,034	-	-	-	(240)	-	(794)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	-	4,542	-	15,060
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	(722)	-	181	-	126	-	416
14		Update benefits costs	-	-	-	(3,060)	-	-	-	709	-	2,351
14(D)		Update benefits costs- Supplemental	-	-	-	(3,298)	-	-	-	764	-	2,534
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	-	1,444	-	4,788
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	42	-	-	-	(10)	-	(32)
16	*	Amortize rate case costs	-	-	-	701	-	-	-	(162)	-	(539)
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	-	341	-	1,129
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	(205)	-	-	-	47	-	157

Smith
Exhibit 1
Page 3

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	-	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	-	988	-	3,276
19(I)		Adjust for Merger Related Costs	-	-	-	-	(12)	-	-	3	-	10
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	-	5,414	-	17,952
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(774)	-	-	-	179	-	594
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	(2,183)	-	2,183
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	123	-	(123)
22(I)		Synchronize interest expense with end of period rate base- Second Supplemental	-	-	-	-	-	-	-	2,959	-	(2,959)
23	*	Adjust cash working capital	-	-	-	-	-	-	-	122	-	(122)
23(I)		Adjust cash working capital- Second Supplemental	-	-	-	-	-	-	-	(35)	-	35
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-	-
24(C)		Adjust coal inventory- Supplemental	-	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	-	(1,204)	-	(3,993)
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	72	-	-	-	(17)	-	(55)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	-	(20,760)	-	(68,841)
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	(873)	-	-	202	-	671
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	-	21	-	70
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	(1,826)	-	-	423	-	1,403
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	-	(10,129)	-	(33,588)
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	-	-	-	-	(45,362)	-	-	10,510	-	34,852
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	-	1,767	-	5,859
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	-	-	-	-	10,381	1,032	-	(2,644)	-	(8,769)
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	-	(1,144)	-	(3,794)
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	(4,939)	-	-	-	1,144	-	3,794
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	-	(4,565)	-	(15,138)
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	-	(7,568)	(4,624)	-	-	2,825	-	9,367

Smith Exhibit 1
Page 3
(continued)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT 0.0000% (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	-	455	-	1,510
36(E)	Correct Lead Lag- Supplemental	-	-	-	-	-	-	-	-	-	-
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	-	-	-	(30,548)	7,078	-	23,470
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	(2,834)	-	-	-	657	-	2,177
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	9,300	-	-	-	(2,155)	-	(7,145)
40	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ -	$ (74,904)	$ (1,481)	$ (319,441)
40(I)	Change from Application	13,351	11,782	-	(10,035)	(53,443)	363	(30,548)	24,987	-	70,243
41	Total adjustments	$ (304,779)	$ (34,636)	$ (1,965)	$ (187,341)	$ 247,926	$ 2,381	$ (30,548)	$ (49,917)	$ (1,481)	$ (249,198)

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1	Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	225,760	-	225,760
1(D)	Annualize retail revenues for current rates- Supplemental	-	-	-	-	-	-	-	-	(24,093)	-	(24,093)
2	Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,311)	-	(14,311)
2(F)	Update fuel costs to proposed rate- Rebuttal	-	-	-	-	-	-	-	-	25,789	-	25,789
3	* Normalize for weather	-	-	-	-	-	-	-	-	59,144	-	59,144
11(E)	Normalize for weather- Supplemental	-	-	-	-	-	-	-	-	(7,142)	-	(7,142)
4	* Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,314)	-	(2,314)
4(I)	Annualize revenues for customer growth- Second Supplemental	-	-	-	-	-	-	-	-	5,613	-	5,613
5	Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,869)	-	(11,869)
6	Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,932)	(94,010)	(261,943)
6(C)	Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	-	-	-	-	-	(31)	230	199
7	Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,408)	-	(2,408)
7(G)	Adjust O&M for executive compensation- Partial Settlement	-	-	-	-	-	-	-	-	(162)	-	(162)
8	Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,290	-	40,290
8(D)	Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	-	-	-	-	(663)	-	(663)
9	Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,079	-	4,079
10	* Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,355	120,182	197,537
10(I)	Adjust for post test year additions to plant in service- Second Supplemental	(187,320)	195,347	-	20,220	(25,761)	-	-	2,486	(3,062)	(69)	(3,131)
11	* Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	106,364	29,499	135,863
11(E)	Amortize deferred environmental costs- Supplemental	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,986)	(2,835)	(12,820)
12	Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,316	-	1,316
12(I)	Annualize O&M non-labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	1,038	-	1,038
13	* Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,674)	-	(19,674)
13(I)	Normalize O&M labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	(544)	-	(544)
14	Update benefits costs	-	-	-	-	-	-	-	-	(3,071)	-	(3,071)
14(D)	Update benefits costs- Supplemental	-	-	-	-	-	-	-	-	(3,310)	-	(3,310)
15	* Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,255)	-	(6,255)
15(E)	Levelize nuclear refueling outage costs- Supplemental	-	-	-	-	-	-	-	-	42	-	42
16	* Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	704	186	889
16(G)	Amortize rate case costs- Partial Settlement	-	-	-	(2,670)	619	-	-	(2,051)	-	(186)	(186)
17	Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,475)	-	(1,475)
17(G)	Adjust aviation expenses- Partial Settlement	-	-	-	-	-	-	-	-	(206)	-	(206)

Smith Exhibit 1 Page 3 (cond)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,878)	(5,821)	(7,699)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,280)	31	(4,248)
19(I)		Adjust for Merger Related Costs	(558)	55	-	-	-	-	-	(504)	(12)	(46)	(58)
20	*	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,453)	1,621	(21,832)
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(23,297)	5,398	-	-	(17,899)	(777)	(1,621)	(2,398)
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,851)	-	(2,851)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22(I)		Synchronize interest expense with end of period rate base- Second Supplemental	-	-	-	-	-	-	-	-	3,865	-	3,865
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	160	(2,447)	(2,287)
23(I)		Adjust cash working capital- Second Supplemental	-	-	-	7,582	-	-	-	7,582	(46)	691	645
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24(C)		Adjust coal inventory- Supplemental	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,922)	(1,922)
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,217	-	5,217
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	-	-	-	-	-	72	-	72
26		Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,933	(8,037)	81,896
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	-	-	-	-	(876)	20	(857)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,779	-	5,779
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	-	-	-	-	(1,833)	-	(1,833)
29	*	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,879	42,594	86,473
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	(68,639)	2,231	-	(612,045)	141,807	-	-	(536,647)	(45,530)	(48,594)	(94,125)
30		Adjust other revenue	-	-	-	-	-	-	-	-	4,165	-	4,165
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(235)	-	(235)
32	*	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,654)	(2,965)	(10,619)
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,456	6,809	18,265
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,957	-	4,957
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	-	-	-	-	-	(4,957)	-	(4,957)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,776	2,230	22,006
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	(248)	(27,188)	6,299	-	-	(21,136)	(12,237)	(1,915)	(14,152)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	EPIS	Accum Deprec	Materials & Supplies	Working Capital	ADIT	Operating Reserves	CWIP	Rate Base	Oper Inc Rev Req Impact	R/B Rev Req Impact	Total Rev Req Impact
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,972)	-	(1,972)
36(E)	Correct Lead Lag- Supplemental	-	-	-	(8,580)	-	-	-	(8,580)	-	(775)	(775)
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	30,548	(7,078)	-	-	23,470	(30,661)	2,121	(28,540)
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	-	-	-	-	-	(2,844)	-	(2,844)
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	-	-	-	-	-	9,334	-	9,334
40	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 417,313	$ 83,718	$ 501,031
40(I)	Change from Application	30,535	(13,039)	(21,565)	(656,564)	130,814	-	-	(529,819)	(91,764)	(47,873)	(139,637)
41	Total adjustments	$ 611,093	$ (115,487)	$ (172,644)	$ 235,143	$ (58,470)	$ -	$ (102,930)	$ 396,705	$ 325,549	$ 35,845	$ 361,394

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

I/A

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(115,487)	(8,157,546)
3	Net electric plant		16,126,825	10,763,851	495,606	11,259,457
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	235,143	(140,029)
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(58,470)	(1,391,098)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 396,705	$ 10,255,755

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

		Total Company	North Carolina Retail Operations		
Line No.	Description	Per Books (Col. 1)	Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (179,365)	$ 9,877,155
2	Transmission Plant	2,746,389	1,643,263	264,402	1,907,665
3	Distribution Plant	6,944,764	6,052,263	433,108	6,485,371
4	General Plant	628,616	465,435	68,399	533,833
5	Intangible Plant	527,370	358,178	51,912	410,090
6	Subtotal	27,398,830	18,575,658	638,456	19,214,114
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (50,423)	$ (4,441,180)
2	Transmission Reserve	(816,198)	(488,611)	(27,693)	(516,304)
3	Distribution Reserve	(3,235,148)	(2,819,386)	26,382	(2,793,003)
4	General Reserve	(167,536)	(124,045)	(30,822)	(154,867)
5	Intangible Reserve	(322,831)	(219,260)	(32,932)	(252,192)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (115,487)	$ (8,157,546)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

I/A

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(28,011)	(b)	132,130	55,637	(c)	187,768
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		263,154		(174,137)	-		(174,137)
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		235,143		(23,441)	55,637		32,197
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 235,143		$ (140,029)	$ 55,637		$ (84,391)

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

I/A

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Smith Exhibit 1 Supplemental Rebuttal

Line No.	Description	Ref #	SUMMARY OF PROPOSED REVENUE ADJUSTMENTS: Application	Partial Settlement	Second Supplemental	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(96,523)	(85,386)	(85,386)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(173,156)	(147,750)	(147,750)
6	Net Revenue Increase		$ 463,619	$ 321,573	$ 358,116	$ 358,116
7						

Line No.	Description	Ref #	CHANGE IN OP INCOME: Application	Partial Settlement	Second Supplemental	Total Adjs [1]		CHANGE IN RATE BASE: Application	Partial Settlement	Second Supplemental	Total Change [2]
8											
9											
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ -	$ (154,370)		$ -	$ -	$ -	$ -
11	Update fuel costs to proposed rate	NC-0200	10,955	-	-	(8,786)		-	-	-	-
12	Normalize for weather	NC-0300	(45,273)	-	-	(39,806)		-	-	-	-
13	Annualize revenues for customer growth	NC-0400	1,771	-	(2,771)	(2,525)		-	-	-	-
14	Eliminate unbilled revenues	NC-0500	9,086	-	-	9,086		-	-	-	-
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	-	128,571		(1,037,885)	-	-	(1,037,885)
16	Adjust O&M for executive compensation	NC-0700	1,843	124	-	1,967		-	-	-	-
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	-	(30,333)		-	-	-	-
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	-	(3,122)		-	-	-	-
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	(9)	(4,732)	(56,870)		1,326,826	(1,507)	139,224	1,329,312
20	Amortize deferred environmental costs	NC-1100	(81,419)	-	-	(73,775)		325,675	-	-	295,100
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	37	1,420	(1,802)		-	-	-	-
22	Normalize O&M labor expenses	NC-1300	15,060	3,009	(3,633)	15,476		-	-	-	-
23	Update benefits costs	NC-1400	2,351	-	-	4,885		-	-	-	-
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	-	4,756		-	-	-	-
25	Amortize rate case costs	NC-1600	(539)	-	-	(539)		2,051	(2,051)	-	-
26	Adjust aviation expenses	NC-1700	1,129	157	-	1,287		-	-	-	-
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	-	1,438		(64,423)	-	-	(64,423)
28	Adjust for Merger Related Costs	NC-1900	3,276	-	2	3,285		347	-	(53)	(157)
29	Amortize Severance Costs	NC-2000	17,952	-	-	18,547		17,899	(16,717)	-	-
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	-	2,183		-	-	-	-
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(2,433)	623	(3,081)		-	-	-	-
32	Adjust cash working capital	NC-2300	(122)	17	(9)	(87)		(27,013)	3,904	(2,116)	(19,431)
33	Adjust coal inventory	NC-2400	-	-	-	-		9,641	-	-	(11,603)
34	Adjust for credit card fees	NC-2500	(3,993)	-	-	(4,048)		-	-	-	-
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	-	(68,170)		(88,728)	-	-	(88,728)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	-	(4,424)		-	-	-	-
37	Adjust reserve for end of life nuclear costs	NC-2800	70	1,403	-	1,473		-	-	-	-
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	34,448	7	1,264		470,238	(531,121)	27	(66,408)
39	Adjust other revenue	NC-3000	(3,188)	-	-	(3,188)		-	-	-	-
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	-	180		-	-	-	-
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	-	-	(2,910)		(32,730)	-	-	42,550
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-	-		-	-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	4,299	-	(5,771)		24,624	(16,124)	-	3,488
44	Adjust Purchased Power	NC-3500	1,510	-	-	1,510		-	-	-	-
45	Correct Lead Lag	NC-3600	-	-	-	-		-	-	-	(8,580)
46	Amortize Prot EDIT	NC-3700	-	23,470	-	23,470		-	23,470	-	23,470
47	Remove certain Settlement Items	NC-3800	-	2,177	-	2,177		-	-	-	-
48	Normalize for storm costs	NC-3900	-	(7,145)	-	(7,145)		-	-	-	-
49											
50		Adjustments	$ (319,441)	$ 59,554	$ (9,094)	$ (249,198)		$ 926,524	$ (540,146)	$ 137,082	$ 396,705
51											
52	Operating income	[3]	675,472	675,472	675,472	675,472	Rate base [4]	9,859,050	9,859,050	9,859,050	9,859,050
53	Total Adjustments		(319,441)	(240,104)	(249,198)	(249,198)	Total Adjustments	926,524	259,622	396,705	396,705
54	Adjusted Net Operating Income		356,031	435,367	426,273	426,273	Adjusted Rate Base	10,785,574	10,118,673	10,255,755	10,255,755
55											
56	Revenue Requirement Impact		417,313	(77,801)	11,880	325,549		83,718	(48,806)	12,386	35,845
			417,313	313,669	325,549	325,549		83,718	23,459	35,845	35,845

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 2
Second Supplemental

Line No.	Description	NC RETAIL		Reference
1	Additional base revenue requirement	$	438,211	Smith Second Supplemental Exhibit 1
2	REVISED Annual EDIT Rider 1		7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback		(85,386)	Smith Second Supplemental Exhibit 4
4	Regulatory Asset and Liability Rider		(2,091)	Smith Exhibit 5
5	Subtotal		(80,096)	Sum L3 - L17
6	Net Revenue Increase	$	358,116	

I/A

DUKE ENERGY PROGRESS, LLC
Reconciliation of Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 3
Second Supplemental

Line No.		Item	Amount
1	Revenue requirement increase per Company application		**585,961**
2	Revenue impact of Company supplemental adjustments		(51,617)
3	Revenue impact of Company rebuttal adjustments		9,918
4	Revenue impact of Settlement adjustments		(131,457)
5	Revenue requirement increase per Company Partial Settlement Filing		**$ 412,805**
6			
7	Updated Proformas:		
8	NC0400	Annualize revenues for customer growth	3,620
9	NC1000	Adjust for post test year additions to plant in service	18,762
10	NC1200	Annualize O&M non-labor expenses	(1,855)
11	NC1300	Normalize O&M labor expenses	4,746
12	NC1900	Adjust merger related costs	(7)
13	NC2200	Adjust synchronized interest expense	(813)
14	NC2300	Adjust cash working capital under present rates	(179)
15	NC2300	Adjust cash working capital under proposed rates	1,141
16	NC2900	Update deferred balance and amortize storm costs	(7)
17	Rounding		(1)
18	Total Revenue impact of adjustments		$ 25,406
19			
20	Revenue Requirement per Smith Exhibit 1 Second Supplemental		**$ 438,211**

Duke Energy Progress, LLC | NC-0400
Docket No. E-2, Sub 1219 | Second Supplemental
Annualize revenues for customer growth
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma annualizes revenue, fuel expense, operation and maintenance expense, and income taxes to reflect changes in the number of customers and usage per customer during the test period.

The impact to revenue was determined as follows:

To determine the additional revenue requirement resulting from customer growth, the monthly increase in number of customers was multiplied by the applicable average monthly kWh consumption per customer to derive the annualized change in kWh consumption based on the number of customers at the end of the test period.

The impact to fuel expense was determined by multiplying the 'Customer growth adjustment to KWH sales - NC kWh adjustment' by the most recent approved fuel rate (excluding EMF).

The impact to other operation and maintenance expense is determined by multiplying the impact to revenue by the statutory regulatory fee percentage rate and the uncollectibles rate.

The impact to income taxes was determined by multiplying taxable income by the statutory tax rate.

This adjustment updates revenues to reflect customer growth experienced beyond the test period, through July 2019. The underlying calculations reflect the same methods used in the Company's rebuttal testimony as explained by Company Witness Pirro in Docket E-2 Sub 1142.

October update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through October 2019

November update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through November 2019

December update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through December 2019
NC-0404 was adjusted to calculate Residential ¢ / kWh excluding the Basic Customer Charge

January update
Updated NC-0403 for weather impacts in NC-300 and customer growth information through January 2020

February update
NC-0402 and NC-0403 now reflect separate adjustments for Customer Growth and Usage
Updated NC-0403 for weather impacts in NC-300 and customer growth information through February 2020
NC-0404 was adjusted to reflect the ¢ / kWh both with and excluding the Basic Customer Charge

Second Supplemental
Updated customer growth and usage kWh through May 2020

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0400
Second Supplemental

Line No.	Description	Source	Total NC Retail				
1			Second Supplemental	April	February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**						
3							
4	Electric operating revenue	NC-0401	$ (10,443)	$ (12,275)	$ (2,159)	$ 5,182	(15,625)
5							
6	Electric operating expenses:						
7	Operation and maintenance						
8	Fuel used in electric generation	NC-0401	(7,118)	(6,577)	(2,471)	2,857	(9,976)
9	Purchased power		-	-	-	-	-
10	Other operation and maintenance expense	NC-0401	(39)	(45)	(8)	19	(58)
11	Depreciation and amortization		-	-	-	-	-
12	General taxes		-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-
14	Income taxes	NC-0401	(761)	(1,309)	74	534	(1,296)
15	Amortization of investment tax credit		-	-	-	-	-
16							
17	Total electric operating expenses	Sum L8 through L15	(7,918)	(7,932)	(2,405)	3,411	(11,329)
18							
19	Operating income	L4 - L17	$ (2,525)	$ (4,342)	$ 246	$ 1,771	$ (4,296)
20							
21	Notes:						
22	Revenue: positive number increases revenue / negative number decreases revenue						
23	Expense: positive number increases expense / negative number decreases expense						
24							
25							
26	**Pro Formas Impacting Rate Base Line Items**						
27							
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-
31							
32	Add:						
33	Materials and supplies		-	-	-	-	-
34	Working capital investment		-	-	-	-	-
35							
36							
37	Less:						
38	Accumulated deferred taxes		-	-	-	-	-
39	Operating reserves		-	-	-	-	-
40							
41							
42	Construction work in progress		-	-	-	-	-
43							
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -	$ -
45							
46	Note:						
47	Rate Base: positive number increases rate base / negative number decreases rate base						

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0401
Second Supplemental

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	SI	Area Service Lighting	Sports Field Lighting Service	Street Lighting Service	Traffic Service Signal	Total NC Retail	
1						NCSI		NCSFL	NCSLS	NCTSS		
2	Customer growth and usage Revenue adjustment	$ 25,674	$ (7,252)	$ (32,527)	$ 3,830	$ (994)	$ -	$ (16)	$ 855	$ (13)	$ (10,443)	[1]
3												
4	Approved fuel and fuel related costs ¢/kWh (excluding EMF)	2.326	2.499	2.456	2.054	2.456	2.217	2.217	2.217	2.217		[2]
5	Customer growth and usage adjustment to kWh sales	210,975,729	(93,344,303)	(439,354,341)	62,259,064	(9,654,269)	-	(104,146)	2,772,245	(140,282)	(266,590,304)	[1]
6	Impact to fuel (L4 x (L5 / 100,000))	$ 4,907	$ (2,333)	$ (10,791)	$ 1,279	$ (237)	$ -	$ (2)	$ 61	$ (3)	$ (7,118)	
7												
8	<u>Calculation of NCUC Regulatory Fee and Uncollectible</u>											
9	Uncollectible rate	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	[3]
10	Statutory regulatory fee percentage rate	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	[4]
11	Impact to O&M ((L9 + L10) x L2)	$ 95	$ (27)	$ (120)	$ 14	$ (4)	$ -	$ (0)	$ 3	$ (0)	$ (39)	
12												
13	Taxable income (L2 - L6 - L11)	$ 20,672	$ (4,893)	$ (21,617)	$ 2,537	$ (753)	$ -	$ (14)	$ 790	$ (10)	$ (3,286)	
14												
15	Statutory tax rate	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	[5]
16	Impact to income taxes (L13 x L15)	$ 4,790	$ (1,134)	$ (5,008)	$ 588	$ (174)	$ -	$ (3)	$ 183	$ (2)	$ (761)	
17												
18	Impact to operating income (L13 - L16)	$ 15,883	$ (3,759)	$ (16,608)	$ 1,949	$ (579)	$ -	$ (10)	$ 607	$ (7)	$ (2,525)	

[1] NC-0402 - Calculation of Customer Growth and Usage Revenue Adjustment
[2] NC-0202 - NC Billed Fuel Factors (with EMF and EMF Interest Increment/Decrement for approved cost factors), Line 8
[3] NC-0105 - 2018 Uncollectibles Rate, Line 4
[4] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate - Adjusted, Docket No. M-100, Sub 142, Line 3
[5] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0402a
Second Supplemental

Calculation of Customer Growth Adjustment

Line No.	Rate Schedule	NC Retail KWH Adjustment (a)	[1]	Cents Per kWh (b)	[2]	Revenue Adjustment (c) = ((a) x (b) / 100,000)
1	Residential	561,198,538		8.85	$	49,654
2	Residential excl. TOU	550,471,121		8.85		48,721
3	Residential TOU	10,727,417		8.70		933
4						
5	Small General Service	39,079,080		10.83	$	4,231
6	SGS excl. Constant Load Rate	37,664,616		10.81		4,073
7	SGS Constant Load Rate	1,414,464		11.20		158
8						
9	Medium General and Seasonal and Intermittent Service	105,085,689		7.66	$	8,048
10	Medium General Service excl. Time of Use	44,209,854		8.73		3,860
11	Medium General Service Time of Use	58,616,356		6.72		3,941
12	Seasonal and Intermittent Service	2,259,479		10.95		247
13						
14	Large General Service	101,703,976		6.14	$	6,247
15	Large General Service excl. Time of Use and Real Time Pricir	30,755,841		6.92		2,129
16	Large General Service Time of Use	42,289,282		6.29		2,662
17	Large General Service Real Time Pricing	28,658,852		5.08		1,456
18						
19	Sports Field Lighting Service	9,130		17.81		2
20	Street Lighting Service	2,772,245		30.84		855
21	Traffic Signal Service	(140,282)		9.15		(13)
22						
23	Total kWh Adjustment (L1 through L21)	809,708,375				
24						
25						
26	NC Residential Change in number of customers	# of Customers	[3]	BCC	[4]	
27	Residential	489,051		$ 14.00	$	6,847
28	Residential TOU	9,530		$ 16.85	$	161
29						
30						76,032

[1] NC-0403 - Customer Growth Adjustment to KWH Sales, col (d)
[2] NC-0404 - Present Revenue Annualized and KWH Sales - NC Retail, c/kWh. Residential uses ¢ / kWh excluding BCC.
[3] Source Rate Design Regression Analysis
[4] Basic Customer Charge per Tariffs - Pirro Exhibit 1: RES-60 $14.00, R-TOU-60 $16.85, and R-TOUD-60 $16.85

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0402b
Second Supplemental

Calculation of Customer Usage Revenue Adjustment

Line No.	Rate Schedule	NC Retail KWH Adjustment (a)	[1]	Cents Per kWh (b)	[2]		Revenue Adjustment (c) = ((a) x (b) / 100,000)
1	Residential	(350,222,809)		8.85		$	(30,987)
2	Residential excl. TOU	(343,528,233)		8.85			(30,405)
3	Residential TOU	(6,694,576)		8.70			(582)
4							
5	Small General Service	(132,423,383)		8.67		$	(11,483)
6	SGS excl. Constant Load Rate	(127,630,328)		8.76			(11,177)
7	SGS Constant Load Rate	(4,793,055)		6.39			(306)
8							
9	Medium General and Seasonal and Intermittent Service	(554,094,299)		7.50		$	(41,570)
10	Medium General Service excl. Time of Use	(233,109,077)		8.53			(19,884)
11	Medium General Service Time of Use	(309,071,473)		6.61			(20,445)
12	Seasonal and Intermittent Service	(11,913,748)		10.42			(1,241)
13							
14	Large General Service	(39,444,912)		6.13		$	(2,417)
15	Large General Service excl. Time of Use and Real Time Pricir	(11,928,358)		6.90			(823)
16	Large General Service Time of Use	(16,401,493)		6.28			(1,029)
17	Large General Service Real Time Pricing	(11,115,061)		5.08			(564)
18							
19	Sports Field Lighting Service	(113,276)		15.46			(18)
20	Street Lighting Service	-		30.84			-
21	Traffic Signal Service	-		9.15			-
22							
23	Total kWh Adjustment (L1 through L21)	(1,076,298,679)					(86,475)

[1] NC-0403 - Customer Growth Adjustment to KWH Sales, col (d)
[2] NC-0404 - Present Revenue Annualized and KWH Sales - NC Retail, c/kWh. Residential uses ¢ / kWh excluding BCC.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0403
Second Supplemental

Customer Growth Adjustment to KWH Sales

Line No.	(a) Rate Schedule	(b) COS Category	(c) NC Proposed Customer Growth kWh Adjustment	(d) NC Proposed Change in Usage kWh Adjustment	(e) NC Proposed KWH Adjustment [1]		(f) Adj by COS Schedule	(f) Adj by COS Schedule	COS Schedules	(g) Service Bases 12/31/2018 C1ALL Allocator [2]	
1											
2	NC Residential	Residential	561,198,538	(350,222,809)	210,975,729	RES, RET	550,471,121	(343,528,233)	NCRES	NCRES	1,177,050
3							10,727,417	(6,694,576)	NCRET	NCRET	22,938
4	NC General:									NCSGS	160,062
5	General Service Small	Small General Service	39,079,080	(132,423,383)	(93,344,303)	SGS, SGSTCLR	37,664,616	(127,630,328)	NCSGS	NCSGSTCLR	6,011
6	General Service Medium	Medium General Service	105,085,689	(554,094,299)	(449,008,610)	MGS, SGS-TOU,SI	1,414,464	(4,793,055)	NCSGSTCLR	NCSGTM	22,077
7	Total General		144,164,769	(686,517,682)	(542,352,913)		58,616,356	(309,071,473)	NCSGTM	NCMGS	16,651
8							44,209,854	(233,109,077)	NCMGS	NCSI	851
9							2,259,479	(11,913,748)	NCSI	NCLGS	88
10	NC Lighting:									NCLGT	121
11	Street Lighting	Lighting	2,772,245	-	2,772,245	SLS/SLR	2,772,245	-	NCSLS	NCRTP	82
12	Sports Field Lighting	Lighting	9,130	(113,276)	(104,146)	SFLS	9,130	(113,276)	NCSFL	NCTSS	780
13	Traffic Signal Service	Lighting	(140,282)	-	(140,282)	TSS/TFS	(140,282)	-	NCTSS	NCALS	0
14	Total Street Lighting		2,641,093	(113,276)	2,527,817					NCSLS	1,578
15										NCSFL	78
16	NC Industrial:										1,408,367
17	I - Textile	Large General Service	-	-	-		30,755,841	(11,928,358)	NCLGS		
18	I - Nontextile	Large General Service	101,703,976	-	101,703,976	LGS incl. TOU & RTP	42,289,282	(16,401,493)	NCLGT		
19	I - Textile & Nontextile	Large General Service	-	(39,444,912)	(39,444,912)		28,658,852	(11,115,061)	NCRTP		
20	Total Industrial		101,703,976	(39,444,912)	62,259,064						
21											
22							809,708,375	(1,076,298,679)			
23	Total		809,708,375	(1,076,298,679)	(266,590,304)						

Notes:
[1] Information provided by Rate Design.
[2] Regression using number of service bases, and schedules in proposed adjustment per Rate Design

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0404
Second Supplemental

Present Revenue Annualized and KWH Sales - NC Retail

Line No.	COS Category	Description	NORTH CAROLINA RETAIL Present Revenue Annualized [1]	Basic Customer Charge (BCC)	Present Revenue Excluding BCC	Per Book kWh Sales [2]	All-Inclusive ¢ / kWh	w/o BCC ¢ / kWh
1								
2	Residential	RES - RESIDENTIAL SERVICE	$ 1,627,945,892	$ (197,751,086)	$ 1,430,194,806	16,158,859,096	10.07	8.85
3		R-TOUD - RESIDENTIAL SERVICE TIME-OF-USE	37,486,504	(4,041,968)	33,444,536	451,040,840		
4		R-TOU - RESIDENTIAL SERVICE ALL-ENERGY TIME-OF-USE	5,576,511	(694,079)	4,882,432	56,146,653	9.93	8.70
5	**Residential Sum**		$ 1,671,008,906	$ (202,487,133)	$ 1,468,521,774	16,666,046,589		
6	Small General Service	SGS - SMALL GENERAL SERVICE	210,976,543	$ (40,117,843)	$ 170,858,700	1,950,982,004	10.81	8.76
7		SGS-TOU-CLR - SMALL GENERAL SERVICE TIME-OF-USE CONSTANT LOAD RATE	3,539,804	(1,520,432)	2,019,372	31,614,397	11.20	6.39
8	**Small General Service Sum**		$ 214,516,347	$ (41,638,275)	$ 172,878,072	1,982,596,401		
9	Medium General Service	APH-TES - AGRICULTURAL POST-HARVEST SERVICE	133,640	$ (1,281)	$ 132,359	2,065,800		
10		CH-TOUE - CHURCH SERVICE EXPERIMENTAL TIME-OF-USE	1,173,027	(95,984)	1,077,043	8,706,511		
11		CSE - CHURCH AND SCHOOL SERVICE	193,536	(14,938)	178,598	1,373,440		
12		CSG - CHURCH AND SCHOOL SERVICE	4,336	(342)	3,994	25,680		
13		MGS - MEDIUM GENERAL SERVICE	242,144,278	(5,603,638)	236,540,640	2,773,108,650	8.73	8.53
14		SGS-TES - SMALL GENERAL SERVICE THERMAL ENERGY STORAGE	1,345,435	(6,090)	1,339,345	21,819,600		
15		SGS-TOU - SMALL GENERAL SERVICE TIME-OF-USE	562,838,889	(9,050,665)	553,788,224	8,371,865,197	6.72	6.61
16	**Medium General Service Sum**		$ 807,833,140	$ (14,772,938)	$ 793,060,202	11,178,964,878		
17	Large General Service	LGS - LARGE GENERAL SERVICE	79,000,414	$ (219,986)	$ 78,780,428	1,141,204,433	6.92	6.90
18		LGS-RTP - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING)	-	-	-	9,861,252		
19		LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	290,057,172	(187,226)	289,869,945	5,708,044,202	5.08	5.08
20		LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	100,616,525	(282,041)	100,334,484	1,598,681,135	6.29	6.28
21	**Large General Service Sum**		$ 469,674,111	$ (689,254)	$ 468,984,857	8,457,791,022		
22	Other	ALS - AREA LIGHTING SERVICE	62,316,881	$ -	$ 62,316,881	267,795,639		
23		SFLS - SPORTS FIELD LIGHTING SERVICE	202,072	(26,622)	175,450	1,134,908	17.81	15.46
24		SLS - STREET LIGHTING SERVICE	26,250,749	-	26,250,749	85,107,971	30.84	
25		TSS - TRAFFIC SIGNAL SERVICE	434,956	-	434,956	4,754,792	9.15	
26	**Other Sum**		$ 89,204,659	$ (26,622)	$ 89,178,037	358,793,310		
27	Seasonal Intermittent	SI - SEASONAL OR INTERMITTENT SERVICE	4,715,715	(228,386)	4,487,329	43,075,313	10.95	10.42
28	**Seasonal Intermittent Sum**		$ 4,715,715	$ (228,386)	$ 4,487,329	43,075,313		
29	Grand Total		$ 3,256,952,878	$ (259,842,608)	$ 2,997,110,271	38,687,267,513		

[1] NC-0102 - Column c
[2] NC-0302 Sum of kWh

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1200
Second Supplemental

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma annualizes test period operation and maintenance expenses excluding fuel, purchased power, and labor and benefit costs to reflect the change in unit costs that occurred during the test period.

The impact to operation and maintenance expenses is determined as follows:

First, calculate total operation and maintenance expense excluding fuel and purchased power but including labor that needs to be adjusted. This calculation is done by starting with per book operation and maintenance expense, excluding fuel and purchased power, and subtracting all pro-forma adjustments that impacted this amount.

Second, subtract net electric operation and maintenance salaries and wages from operation and maintenance expenses including labor.

Third, subtract fringe benefits from operation and maintenance expenses including labor. Fringe benefits are calculated by multiplying net electric operation and maintenance salaries and wages by the fringe benefits contribution rate.

Finally, the impact to operation and maintenance expense is calculated by multiplying total non-labor operation and maintenance expenses by the average inflation rate.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update

Updated NC-1201 to remove CertainTeed cost adjustment in accordance with Commission order under Docket No. E-2, Sub 1204

November update

Updated NC-1203, NC-1204 and NC-1205 for most up to date index values

December update

Updated index values on NC-1203, NC-1204 and NC-1205 and for impacts flowing from other adjustments

January update

Updated index values on NC-1203, NC-1204 and NC-1205 and for impacts flowing from other adjustments

February update

Updated for impacts flowing from other adjustments; No revision made to index values as updates were no available as of Supplemental filing date

Rebuttal

Updated NC-1203, NC-1204 and NC-1205 for index values through February 2020.
Updated average inflation rate on NC-1201

April update

Updated NC-1203, NC-1204 and NC-1205 for index values through April 2020.
Updated average inflation rate on NC-1201

Second Supplemental

Updated NC-1203, NC-1204 and NC-1205 for index values through May 2020.
Updated average inflation rate on NC-1201

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Source	Second Supplemental
1			
2	**Pro Formas Impacting Income Statement Line Items**		
3			
4	Electric operating revenue		$ -
5			
6	Electric operating expenses:		
7	Operation and maintenance		
8	Fuel used in electric generation		-
9	Purchased power		-
10	Other operation and maintenance expense	NC-1201	2,345
11	Depreciation and amortization		-
12	General taxes		-
13	Interest on customer deposits		-
14	Income taxes	NC-1201	(543)
15	Amortization of investment tax credit		-
16			
17	Total electric operating expenses	Sum L6 through L15	1,802
18			
19	Operating income	L4 - L17	$ (1,802)
20			
21	Notes:		
22	Revenue: positive number increases revenue / negative number decreases revenue		
23	Expense: positive number increases expense / negative number decreases expense		
24			
25			
26	**Pro Formas Impacting Rate Base Line Items**		
27			
28	Electric plant in service		$ -
29	Accumulated depreciation and amortization		-
30	Electric plant in service, net	Sum L28 through L29	-
31			
32	Add:		
33	Materials and supplies		-
34	Working capital investment		-
35			
36			
37	Less:		
38	Accumulated deferred taxes		-
39	Operating reserves		-
40			
41			
42	Construction work in progress		-
43			
44	Total impact to rate base	Sum L30 through L42	$ -
45			
46	Note:		
47	Rate Base: positive number increases rate base / negative number decreases rate base		

I/A

Duke Energy Progress, LLC | NC-1201
Docket No. E-2, Sub 1219 | Second Supplemental
Annualize O&M non-labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Second Supplemental Total System		NC Retail Allocation		Total NC Retail	
1							
2							
3	O&M (excluding fuel and purchased power)	$ 1,546,719	[1]			$ 1,050,819	[1]
4							
5	Less: reagents expense and proceeds from sale of by-products	(102,730)	[2]			(62,778)	[2]
6	Less: costs recovered through non-fuel riders	(192,911)	[3]			(136,143)	[3]
7	Less: Ernst & Young outside tax services contract	(592)	[4]	66.2120%	[20]	(392)	[4]
8	Less: nuclear refueling outage costs	(40,225)	[5]			(40,225)	[5]
9	Less: amortization of prior rate case costs	(1,012)	[6]			(1,012)	[6]
10	Less: aviation expenses	(1,579)	[7]	66.2120%	[20]	(1,045)	[7]
11	Less: expiring amortizations	(1,673)	[8]			(1,673)	[8]
12	Less: merger related costs	(5,969)	[9]			(4,039)	[9]
13	Less: severance and retention costs	(52,890)	[10]	66.2120%	[20]	(35,020)	[10]
14	Less: vegetation management expenses - distribution	(36,515)	[11]	83.9171%	[18]	(30,643)	[11]
15	Less: vegetation management expenses - transmission	(8,143)	[11]	59.6699%	[19]	(4,859)	[11]
16	Less: NCUC regulatory fee	(4,889)	[12]			(4,889)	[12]
17	Less: CertainTeed payment obligation	-	[13]	61.1093%	[21]	-	[13]
18	Less: Public Staff Settlement - outside services	(52)	[23]	61.5278%	[23]	(32)	[23]
19	Less: Public Staff Settlement - sponsorships	(38)	[23]	61.5278%	[23]	(23)	[23]
20	Less: Public Staff Settlement - lobbying	(2,429)	[23]	61.5278%	[23]	(1,494)	[23]
21	Less: Public Staff Settlement - board of directors expenses	(2,086)	[23]	61.5278%	[23]	(1,283)	[23]
22							
23	Total O&M to be adjusted including labor (Sum L3 through L21)	$ 1,092,987				$ 725,270	
24							
25	Net electric O&M salaries and wages	$ 649,874	[14]				
26	Fringe benefits contribution rate	20.50%	[15]				
27	Fringe benefits (L25 x L26)	$ 133,210					
28							
29	Less: net electric O&M salaries & wages and fringe benefits (L25 + L27)	$ 783,084		66.2120%	[20]	$ 518,496	
30							
31	Total non-labor O&M to be adjusted (L23 - L29)	$ 309,903				$ 206,774	
32	Average inflation rate	1.13%	[16]			1.13%	[15]
33	Impact to O&M - non-labor O&M adjustment to reflect end of period costs (L31 x L32)	$ 3,514				$ 2,345	
34							
35	Statutory tax rate	23.1693%	[17]			23.1693%	[16]
36	Impact to income taxes (-L33 x L35)	$ (814)				$ (543)	
37	Impact to operating income (-L33 - L36)	$ (2,700)				$ (1,802)	

[1] Smith Exhibit 1, Other O&M, Page 1, Line 4, Columns 1 and 2
[2] NC-0201 - Update fuel costs to approved rate
[3] NC-0601 - Eliminate costs recovered through non-fuel riders, Line 23
[4] NC-1311 - Adjustment to annualized Ernst & Young outside tax services contract, Line 2
[5] NC-1501 - Levelize nuclear refueling outage costs, Line 21
[6] E-1 Item 45A
[7] NC-1702 - Adjust aviation expenses, Line 5
[8] NC-1801 - Adjust for approved regulatory assets and liabilities, Line 3
[9] NC-1901 - Adjust for merger related costs, Line 4
[10] NC-2001 - Amortize severance costs - Actuals, Line 4
[11] NC-2702 - Adjust for vegetation management - distribution and transmission, Lines 11 and 23
[12] E-1 Item 45A
[13] NC-3301, Line 10
[14] NC-1301, Line 14
[15] NC-1301, Line 34
[16] NC-1203 - Average of Consumer Price Index and Producer Price Index, Line 19
[17] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[18] NC Retail Allocation Factor - RB_PLT_O_DI_OH_LN
[19] NC Retail Allocation Factor - DTALL
[20] NC Retail Allocation Factor - LAB
[21] NC Retail Allocation Factor - E1ALL
[22] NC-2503 - Annualized credit/debit card and ACH transactions - NC Residential Only - Line 24
[23] NC-3601 - Settlement adjustment to remove certain items

Duke Energy Progress, LLC | NC-1202
Docket No. E-2, Sub 1219 | Second Supplemental
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

Average of Consumer Price Index and Producer Price Index

Line No.	Period	CPI [1] (a)	PPI [2] Finished goods less food & energy (b)	PPI [3] Processed materials less food & energy (c)	PPI Average (d)= Average of (b) and (c)
1	December 2017	246.5	200.6	196.3	
2	January 2018	247.9	200.9	197.2	
3	February 2018	249.0	201.3	198.3	
4	March 2018	249.6	201.8	199.3	
5	April 2018	250.5	202.3	199.8	
6	May 2018	251.6	202.7	201.3	
7	June 2018	252.0	203.1	202.3	
8	July 2018	252.0	203.7	203.0	
9	August 2018	252.1	204.2	203.7	
10	September 2018	252.4	204.6	204.5	
11	October 2018	252.9	205.1	204.8	
12	November 2018	252.0	205.6	204.2	
13	December 2018	251.2	205.8	203.1	
14					
15	May 2020	256.4	209.8	195.0	
16					
17	13 month average	250.8	203.2	201.4	
18					
19	Increase from average to year end (L15 - L17)	5.6	6.6	(6.4)	
20	% increase from average to year end (L19 / L17)	2.23%	3.25%	-3.18%	0.04%
21	Average inflation rate (Average, Line 18, Col. (a) and Col. (d))	1.13%			

[1] NC-1203 - Consumer Price Index - All Items
[2] NC-1204 - Producer Price Index - Commodities - Finished goods less food and energy
[3] NC-1205 - Producer Price Index - Commodities - Processed materials less food and energy

Note: Totals may not foot due to rounding.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1203
Second Supplemental

Consumer Price Index - All Urban Consumers
Original Data Value

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	211.1	212.2	212.7	213.2	213.9	215.7	215.4	215.8	216.0	216.2	216.3	215.9	214.5
2010	216.7	216.7	217.6	218.0	218.2	218.0	218.0	218.3	218.4	218.7	218.8	219.2	218.1
2011	220.2	221.3	223.5	224.9	226.0	225.7	225.9	226.5	226.9	226.4	226.2	225.7	224.9
2012	226.7	227.7	229.4	230.1	229.8	229.5	229.1	230.4	231.4	231.3	230.2	229.6	229.6
2013	230.3	232.2	232.8	232.5	232.9	233.5	233.6	233.9	234.1	233.5	233.1	233.0	233.0
2014	233.9	234.8	236.3	237.1	237.9	238.3	238.3	237.9	238.0	237.4	236.2	234.8	236.7
2015	233.7	234.7	236.1	236.6	237.8	238.6	238.7	238.3	237.9	237.8	237.3	236.5	237.0
2016	236.9	237.1	238.1	239.3	240.2	241.0	240.6	240.8	241.4	241.7	241.4	241.4	240.0
2017	242.8	243.6	243.8	244.5	244.7	245.0	244.8	245.5	246.8	246.7	246.7	246.5	245.1
2018	247.9	249.0	249.6	250.5	251.6	252.0	252.0	252.1	252.4	252.9	252.0	251.2	251.1
2019	251.7	252.8	254.2	255.5	256.1	256.1	256.6	256.6	256.8	257.3	257.2	257.0	255.7
2020	258.0	258.7	258.1	256.4	256.4								257.5

Source: Bureau of Labor Statistics

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1204
Second Supplemental

Producer Price Index-Commodities
Original Data Value

Series Id: WPSFD4131
Seasonally Adjusted
Group: Final demand
Item: Finished goods less foods and energy
Base Date: 198200
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	170.8	170.9	171.2	171.3	171.2	171.8	171.4	171.8	171.6	171.5	172.1	172.1	171.5
2010	172.5	172.6	172.9	172.9	173.4	173.6	173.7	173.9	174.3	174.3	174.3	174.6	173.6
2011	175.3	175.7	176.2	176.8	177.0	177.6	178.2	178.5	179.0	179.4	179.6	180.0	177.8
2012	180.7	181.0	181.3	181.6	181.8	182.1	182.9	183.2	183.2	183.3	183.7	183.7	182.4
2013	183.9	184.2	184.4	184.6	184.8	185.0	185.2	185.3	185.4	185.6	185.9	186.7	185.1
2014	187.5	187.7	187.7	187.9	188.2	188.5	188.7	189.0	189.2	189.7	189.7	189.8	188.6
2015	190.7	191.3	191.5	191.6	191.8	192.7	193.0	193.0	193.2	193.0	193.1	193.4	192.4
2016	193.9	194.2	194.3	194.6	194.9	195.4	195.4	195.7	195.8	196.1	196.3	196.7	195.3
2017	197.1	197.4	197.8	198.5	198.6	198.8	198.9	199.2	199.2	200.0	200.5	200.6	198.9
2018	200.9	201.3	201.8	202.3	202.7	203.1	203.7	204.2	204.6	205.1	205.6	205.8	203.4
2019	206.6	206.9	207.2	207.5	207.8	207.7	208.1	208.2	208.4	208.4	208.8	208.7	207.9
2020	208.7	209.1	209.7	209.6	209.8								209.4

Source: Bureau of Labor Statistics

Note: Items highlighted green above are preliminary. All indexes are subject to revision four months after original publication.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize O&M non-labor expenses
For the test period ended December 31, 2018

NC-1205
Second Supplemental

Producer Price Index-Commodities
Original Data Value

Series Id: WPSID69115
Seasonally Adjusted
Group: Intermediate demand by commodity type
Item: Processed materials less foods and
Base Date: 198200
Years: 2009 to 2019

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2009	174.8	173.5	172.7	171.8	171.4	171.8	172.2	173.2	174.2	174.5	174.9	175.9	173.4
2010	177.0	178.4	179.6	181.4	181.8	180.9	180.2	180.5	180.9	182.0	183.1	184.1	180.8
2011	186.6	188.8	190.2	192.4	193.5	193.7	194.2	194.2	194.2	193.0	192.3	191.3	192.0
2012	192.0	193.2	194.5	194.7	194.1	191.9	191.2	191.3	192.0	192.2	192.1	192.6	192.7
2013	193.7	194.7	194.4	193.9	193.6	193.5	193.3	193.7	193.7	193.6	193.6	194.0	193.8
2014	194.6	195.2	194.8	195.1	195.0	195.1	195.9	196.3	196.3	195.8	194.9	193.9	195.2
2015	191.8	191.1	190.5	190.1	190.1	190.2	190.0	189.1	188.1	187.7	187.1	186.6	189.4
2016	185.8	185.2	185.1	185.7	186.2	186.6	186.9	187.4	187.7	188.0	188.7	189.4	186.9
2017	190.0	191.3	192.1	192.9	192.8	193.1	192.9	193.5	194.2	195.0	196.0	196.3	193.3
2018	197.2	198.3	199.3	199.8	201.3	202.3	203.0	203.7	204.5	204.8	204.2	203.1	201.8
2019	203.1	202.7	202.4	202.2	201.7	201.0	200.7	200.0	199.7	200.2	199.8	199.4	201.1
2020	199.6	199.2	199.1	196.2	195.0								197.8

Source: Bureau of Labor Statistics

Note: Items highlighted green above are preliminary. All indexes are subject to revision four months after original publication.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1300
Second Supplemental

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro-forma adjusts operation and maintenance expense, general taxes and income taxes to normalize operation and maintenance labor costs.

The impact to operation and maintenance expense is determined as follows:

1. The salaries and wages booked during the test period are subtracted from salaries and wages at June 30, 2019 per Human Resources.
2. The percentage of electric operation and maintenance expense to apply to the salaries and wages adjustment is calculated as follows: total operation and maintenance labor per Form 1, Page 354 is divided by total salaries and wages excluding other work in progress and allocation of clearing accounts per Form 1, Page 355. The adjustment calculated in Step 1 i multiplied by this percentage.
3. The impact to related fringe benefit costs is calculated by multiplying the salaries and wage adjustment calculated in Step 1 by the fringe benefits contribution rate. The fringe benefits contribution rate is calculated by dividing account 926 - employee pensions and benefits booked during the test period by total operation and maintenance labor per Form 1, Page 354.
4. The impact to operation and maintenance expense also reflects an adjustment to restate variable short and long term pay booked during the test period to target.

The impact to general taxes reflects the change in the FICA tax base. To adjust general taxes, the salaries and wages adjustment calculated in Step 1 is multiplied by the percentage of wages subject to OASDI by the OASDI tax rate for employers. Next, the adjustment due to Medicare tax is calculated by multiplying the salaries and wages adjustment calculated in Step 1 by the Medicare tax rate.

The impact to income taxes was determined by multiplying taxable income by the statutory tax rate.

October Update
NC-1304, and NC1305 have all been updated for 12 months ended October 2019

November Update
NC-1304, and NC1305 have all been updated for 12 months ended November 2019

December Update
NC-1304, and NC1305 have all been updated for 12 months ended December 2019
NC-1311 E&Y Fees have been updated for 2019 Actuals

January Update
NC-1304, and NC1305 have all been updated through January 2020

February Update
NC-1304, and NC1305 have all been updated through February 2020

Settlement
NC-1312 added for settled Methodology which excludes STIP and LTIP tied to EPS for executives and those who are eligible for LTIP, Line 11 & 20

Second Supplemental
NC-1304 and NC1305 were updated through May 2020.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1300
Second Supplemental

Line No.	Description	Source	Total NC Retail Second Supplemental	April	Partial Settlement	Application	Change
1			Second Supplemental	April	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**						
3							
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -
5							
6	Electric operating expenses:						
7	Operation and maintenance						
8	Fuel used in electric generation		-	-	-	-	-
9	Purchased power		-	-	-	-	-
10	Other operation and maintenance expense	NC-1301	(19,235)	(18,144)	(23,710)	(18,512)	(722)
11	Depreciation and amortization		-	-	-	-	-
12	General taxes	NC-1301	(909)	(847)	(1,162)	(1,089)	181
13	Interest on customer deposits		-	-	-	-	-
14	Income taxes	NC-1301	4,667	4,400	5,763	4,542	126
15	Amortization of investment tax credit		-	-	-	-	-
16							
17	Total electric operating expenses	Sum L8 through L15	(15,476)	(14,591)	(19,109)	(15,060)	(416)
18							
19	Operating income	L4 - L17	$ 15,476	$ 14,591	$ 19,109	$ 15,060	$ 416
20							
21	Notes:						
22	Revenue: positive number increases revenue / negative number decreases revenue						
23	Expense: positive number increases expense / negative number decreases expense						
24							
25							
26	**Pro Formas Impacting Rate Base Line Items**						
27							
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-
31							
32	Add:						
33	Materials and supplies		-	-	-	-	-
34	Working capital investment		-	-	-	-	-
35							
36							
37	Less:						
38	Accumulated deferred taxes		-	-	-	-	-
39	Operating reserves		-	-	-	-	-
40							
41							
42	Construction work in progress		-	-	-	-	-
43							
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -	$ -
45							
46	Note:						
47	Rate Base: positive number increases rate base / negative number decreases rate base						

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Labor Per Books		As of 5/31/2020 HR Salaries		Pro Forma HR salaries	
1							
2	Salaries and Wages by Payroll Company						
3	Duke Energy Carolinas - salaries and wages - charged to Duke Energy Progress	$ 85,883	[1]	$ 83,631	[2]	$ (2,253)	
4	Service Company DEBS - salaries and wages - charged to Duke Energy Progress	133,040	[1]	131,956	[2]	(1,084)	
5	Duke Energy Progress - salaries and wages	425,470	[1]	402,293	[2]	(23,177)	
6	Total salaries and wages (Sum L3 through L5)	$ 644,394		$ 617,880		$ (26,514)	
7							
8	Calculation of Electric O&M % to Apply to Salaries & Wages Adjustment						
9	Total salaries and wages (Form 1, Page 355, Line 96, Col (d))	$ 878,621	[4]				
10	Less: other work in progress (Form 1, Page 355, Line 78, Col (b))	4,751	[4]				
11	Less: allocation of payroll charged for clearing accounts (Form 1, Page 355, Line 96, Col (c))	18,495	[4]				
12	Total salaries and wages - excluding other WIP and allocation of clearing accounts (L9 - L10 - L11)	$ 855,375					
13							
14	Total operating and maintenance (Form 1, Page 354, Line 28, Col (b))	$ 649,874	[4]				
15							
16	Percent of incurred costs charged to electric expense (L14 / L12)	75.98%				75.98%	
17	Net electric O&M salaries and wages to adjust (L6 x L16)					$ (20,144)	
18							
19	Adjustment to General Taxes - FICA						
20	Net electric O&M salaries and wages to adjust (L17)					$ (20,144)	
21	Percentage of wages subject to OASDI					86.49%	[5]
22	Electric wage adjustment subject to OASDI tax (L20 x L21)					$ (17,422)	
23	OASDI tax rate (employers)					6.20%	[6]
24	Adjustment due to wage adjustment (before Medicare rate) (L22 x L23)					$ (1,080)	
25							
26	Net electric O&M salaries and wages to adjust (L17)					$ (20,144)	
27	Medicare tax rate					1.45%	[6]
28	Adjustment due to Medicare tax (L26 x L27)					$ (292)	
29	Impact to general taxes (L24 + L28)					$ (1,372)	
30							
31	Calculation of Fringe Benefits Contribution Rate						
32	Account 926 - employee pensions and benefits - 12 Months Ended December 31, 2018	$ 133,210	[7]				
33	Total operating and maintenance (Form 1, Page 354, Line 28, Col (b)) (L14)	649,874					
34	Fringe benefits contribution rate (L32 / L33)	20.50%					

NC-1301
Page 1 of 2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description			Total System		NC Retail Allocation		Total NC Retail	
35									
36	Calculation of O&M (Including Fringe Benefits & Variable Pay) and Income Tax								
37	Net electric O&M salaries and wages to adjust (L17)		$	(20,144)					
38	Fringe benefits contribution rate (L34)			20.50%					
39	Fringe benefits adjustment (L37 x L38)		$	(4,129)					
40									
41	Adjustment to restate variable short and long term pay at target	NC-1310	$	(5,950)	[8]				
42	Adjustment to Annualize E&Y Tax Service Contract	NC-1311	$	1,173					
43									
44	Impact to O&M (L37 + L39 + L41)		$	(29,050)		66.2120% [9]	$	(19,235)	
45									
46	Impact to general taxes (L29)		$	(1,372)		66.2120% [9]	$	(909)	
47									
48	Taxable income (-L44 - L46)		$	30,422			$	20,143	
49	Statutory tax rate			23.1693%	[10]			23.1693%	[10]
50	Impact to income taxes (L48 x L49)		$	7,049			$	4,667	
51									
52	Impact to operating income (L48 - L50)		$	23,374			$	15,476	

[1] NC-1302 - Salaries and Wages by Payroll Company for Duke Energy Progress - 12 Months Ended Dec 31, 2018
[2] NC-1304 - Annual Salary Information by Payroll Company for Duke Energy Progress - Dec 31, 2019
[4] NC-1306 - Distribution of Salaries and Wages, 12 Months Ended December 31, 2018 (Form 1, Page 354-355)
[5] NC-1307 - Quarterly Federal Tax Summary Report
[6] NC-1308 - OASDI and SSI Program Rates & Limits - 2019
[7] NC-1309 - Duke Energy Progress - (926) Employee Pensions and Benefits - 12 Months Ended December 31, 2018
[8] NC-1310 - Variable Short and Long Term Pay for Duke Energy Progress
[9] NC Retail Allocation Factor - LAB
[10] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1302
Second Supplemental

Salaries and Wages by Payroll Company for Duke Energy Progress - 12 Months Ended December 31, 2018

Line No.	Payroll Company	Resource Category	Capital	O&M	Total	
1						
2	Duke Energy Carolinas (Payroll Company 100) - charged to DE Progress	Direct Labor	$ 14,986,733	$ 49,780,040	$ 64,766,773	75.41%
3	Duke Energy Carolinas (Payroll Company 100) - charged to DE Progress	Allocated Labor	2,634,654	18,481,953	21,116,607	24.59%
4	Subtotal		$ 17,621,387	$ 68,261,993	$ 85,883,380	100.00%
5						
6	Service Company (Payroll Company 110) - charged to DE Progress	Direct Labor	$ 35,368,447	$ 78,383,690	$ 113,752,137	85.50%
7	Service Company (Payroll Company 110) - charged to DE Progress	Allocated Labor	6,659,597	12,628,346	19,287,943	14.50%
8	Subtotal		$ 42,028,044	$ 91,012,036	$ 133,040,080	100.00%
9						
10	Duke Energy Progress (Payroll Company 801)	Direct Labor	$ 102,240,101	$ 252,616,285	$ 354,856,386	83.40%
11	Duke Energy Progress (Payroll Company 801)	Allocated Labor	20,004,454	50,609,387	70,613,841	16.60%
12	Subtotal		$ 122,244,555	$ 303,225,672	$ 425,470,227	100.00%
13						
14	Total		$ 181,893,987	$ 462,499,701	$ 644,393,688	

Note: Totals may not foot due to rounding
Source: Duke Energy Progress General Accounting and Reporting

[BLANK PAGE]

There are no joint owner reimbursements to consider.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1304
Second Supplemental

Annual Salary Information by Payroll Company for Duke Energy Progress - May 31, 2020

Line No.	Payroll Company	Grand Total	
1			
2	Duke Energy Carolinas (Payroll Company 100)	$ 811,096,827	[2]
3	Duke Energy Carolinas % of labor charged to Duke Energy Progress	10.31%	[1]
4	Duke Energy Carolinas labor charged to Duke Energy Progress (L2 x L3)	$ 83,630,689	
5			
6	Service Company (Payroll Company 110)	$ 763,520,468	[2]
7	Service Company % of labor charged to Duke Energy Progress	17.28%	[1]
8	Service Company labor charged to Duke Energy Progress (L6 x L7)	$ 131,955,965	
9			
10	Duke Energy Progress (Payroll Company 801)	$ 440,885,611	[2]
11	Duke Energy Progress % of labor charged to Duke Energy Progress	91.25%	[1]
12	Duke Energy Progress labor charged to Duke Energy Progress (L10 x L11)	$ 402,292,976	
13			
14	Total - sum of annual salaries (L4 + L8 + L12)	$ 617,879,630	

[1] NC-1305 - Labor Allocations by Business Unit Group - 12 Months Ended May 31, 2020
[2] Information provided by Duke Energy Human Resources Operations

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1305
Second Supplemental

Labor Allocations by Business Unit Group - 12 Months Ended May 31, 2020
Base Labor Resource Types Included: 11000, 11002, 18000, 18001, 18005

Line No.	Resp Center Level 2 Node Name LVL	BU Group	Monetary Amount JD	Percentage
1				
2	100_DUKE_POWER_CONSO	1. DE Carolinas	$ 662,294,442	82.85%
3	100_DUKE_POWER_CONSO	2. DE Progress	82,428,043	10.31%
4	100_DUKE_POWER_CONSO	3. DEBS	823,576	0.10%
5	100_DUKE_POWER_CONSO	4. Other	53,886,837	6.74%
6	100_DUKE_POWER_CONSO		$ 799,432,898	100.00%
7				
8	110_SERVICE_COMPANY	1. DE Carolinas	$ 189,697,243	25.03%
9	110_SERVICE_COMPANY	2. DE Progress	131,000,769	17.28%
10	110_SERVICE_COMPANY	3. DEBS	49,016,522	6.47%
11	110_SERVICE_COMPANY	4. Other	388,279,006	51.22%
12	110_SERVICE_COMPANY		$ 757,993,540	100.00%
13				
14	801_DE_PROGRESS	1. DE Carolinas	$ 30,593,108	6.92%
15	801_DE_PROGRESS	2. DE Progress	403,178,791	91.25%
16	801_DE_PROGRESS	3. DEBS	160,173	0.04%
17	801_DE_PROGRESS	4. Other	7,924,331	1.79%
18	801_DE_PROGRESS		$ 441,856,403	100.00%
19				
20	Total		$ 1,999,282,841	

Source: Duke Energy Corporate Accounting

I/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	221,082,961		
4	Transmission	8,332,490		
5	Regional Market			
6	Distribution	20,838,503		
7	Customer Accounts	21,023,608		
8	Customer Service and Informational	2,244,420		
9	Sales	4,977,267		
10	Administrative and General	144,784,387		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	423,283,636		
12	Maintenance			
13	Production	166,244,358		
14	Transmission	10,965,389		
15	Regional Market			
16	Distribution	49,241,516		
17	Administrative and General	139,214		
18	TOTAL Maintenance (Total of lines 13 thru 17)	226,590,477		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	387,327,319		
21	Transmission (Enter Total of lines 4 and 14)	19,297,879		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	70,080,019		
24	Customer Accounts (Transcribe from line 7)	21,023,608		
25	Customer Service and Informational (Transcribe from line 8)	2,244,420		
26	Sales (Transcribe from line 9)	4,977,267		
27	Administrative and General (Enter Total of lines 10 and 17)	144,923,601		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	649,874,113	3,710,561	653,584,674
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	649,874,113	3,710,561	653,584,674
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	163,441,091	14,784,255	178,225,346
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	163,441,091	14,784,255	178,225,346
72	Plant Removal (By Utility Departments)			
73	Electric Plant	30,303,443		30,303,443
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	30,303,443		30,303,443
77	Other Accounts (Specify, provide details in footnote):			
78	Non-Regulated Products and Services	4,750,987		4,750,987
79	Other Work in Progress	4,471,750		4,471,750
80	Other Accounts	7,284,796		7,284,796
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	16,507,533		16,507,533
96	TOTAL SALARIES AND WAGES	860,126,180	18,494,816	878,620,996

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

Source: Duke Energy HR Operations

Quarterly Federal Tax Summary Report (Report ID: TAX010FD) - Summary

Line No.	Description	(a)		(b)		(c)		12 Months Ended Dec 31, 2018 (d)	
1		(a)		(b)		(c)		(d)	
2	Duke Energy Carolinas								
3	100 Duke Energy Carolinas, LLC OASDI [ER] YTD Gross Wages							$ 1,087,229,757	[1]
4	100 Duke Energy Carolinas, LLC OASDI [ER] YTD Taxable Wages							938,515,849	[1]
5	Percentage Total (L4 / L3)							86.32%	
6									
7	Duke Energy Business Services								
8	110 Duke Energy Business Services, LLC OASDI [ER] YTD Gross Wages							$ 950,101,600	[2]
9	110 Duke Energy Business Services LLC OASDI [ER] YTD Taxable Wages							778,374,460	[2]
10	Percentage Total (L9 / L8)							81.93%	
11									
12	Duke Energy Progress								
13	801 Duke Energy Progress, LLC OASDI [ER] YTD Gross Wages							$ 613,149,643	[3]
14	801 Duke Energy Progress, LLC OASDI [ER] YTD Taxable Wages							539,237,877	[3]
15	Percentage Total (L14 / L13)							87.95%	
16									
17	Calculation of Percentage of Wages Subject to OASDI								
18	For 12 Months Ended December 31, 2018								
19	Duke Energy Carolinas	$ 85,883,380	[4]	13.33%	[5]	86.32%	[8]	11.50%	[11]
20	Duke Energy Business Services	133,040,080	[4]	20.65%	[6]	81.93%	[9]	16.91%	[11]
21	Duke Energy Progress	425,470,227	[4]	66.03%	[7]	87.95%	[10]	58.07%	[11]
22	Total (Sum L19 through L21)	$ 644,393,688		100.00%				86.49%	

[1] NC-1307, Quarterly Federal Tax Summary Report - 4th Quarter 2018, Company: 100
[2] NC-1307, Quarterly Federal Tax Summary Report - 4th Quarter 2018, Company: 110
[3] NC-1307, Quarterly Federal Tax Summary Report - 4th Quarter 2018, Company: 801
[4] NC-1302 - Salaries and Wages by Payroll Company for Duke Energy Progress - 12 Months Ended December 31, 2018
[5] Column (a), Line 19 divided by Line 22
[6] Column (a), Line 20 divided by Line 22
[7] Column (a), Line 21 divided by Line 22
[8] Column (d), Line 5
[9] Column (d), Line 10
[10] Column (d), Line 15
[11] Column (b) multiplied by Column (c)

NC-1307
Page 1 of 2

I/A

Quarterly Federal Tax Summary Report

Company	Quarter	Tax Authorit	EIN	Tax	QTD Withheld	QTD Taxable Wages	QTD Gross Wages	YTD Tax Withheld	YTD Taxable Wages	YTD Gross Wages
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Additional Medicare Tax	104,974.70	11,663,853.10	11,663,853.10	282,793.95	31,421,542.88	31,421,542.88
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Federal Withholding	28,536,104.44	217,903,543.03	247,576,721.94	128,668,020.04	951,227,720.66	1,085,375,221.61
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	FUI (ER)	7,814.72	1,302,349.11	247,394,057.93	425,889.10	70,981,398.12	1,085,502,960.39
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Medicare (ER)	3,427,570.58	236,384,057.64	247,916,479.73	15,075,010.04	1,039,655,751.63	1,087,229,756.77
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	Medicare	3,427,602.66	236,384,552.37	247,936,628.56	15,075,015.30	1,039,656,246.36	1,087,229,699.23
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	OASDI (ER)	11,044,837.60	178,142,417.46	247,916,479.73	58,187,990.70	938,515,848.91	1,087,229,756.77
100 Duke Energy Carolinas, LLC	2018-Q4	Federal	56-0205520	OASDI	11,044,869.55	178,142,912.19	246,965,125.67	58,188,013.61	938,516,343.64	1,084,491,252.86
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Additional Medicare Tax	191,753.93	21,305,989.49	21,305,989.49	651,529.46	72,392,154.27	72,392,154.27
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Federal Withholding	24,460,997.11	182,836,171.89	207,390,610.00	122,163,890.03	835,162,767.20	947,110,242.18
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	FUI (ER)	8,159.62	1,359,946.18	207,624,794.33	375,114.04	62,519,025.03	948,631,033.96
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Medicare (ER)	2,872,403.28	198,096,763.28	208,008,186.10	13,197,524.85	910,174,139.03	950,101,596.15
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	Medicare	2,872,409.66	198,097,158.67	208,059,234.06	13,197,530.70	910,174,542.29	950,064,243.15
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	OASDI (ER)	9,085,708.46	146,543,683.20	208,008,190.06	48,259,216.85	778,374,459.54	950,101,600.11
110 Duke Energy Business Services, LLC	2018-Q4	Federal	56-2115358	OASDI	9,085,473.10	146,543,922.04	204,973,055.80	48,259,232.15	778,374,706.55	935,817,798.97
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Additional Medicare Tax	39,261.27	4,362,352.52	4,369,223.21	101,191.04	11,243,439.39	11,250,310.08
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Federal Withholding	15,957,342.77	123,629,596.26	140,175,939.25	71,856,843.21	537,401,484.37	612,187,559.85
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	FUI (ER)	4,006.42	667,734.28	140,002,620.05	239,162.45	39,860,404.92	612,429,759.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Medicare (ER)	1,940,423.35	133,822,341.37	140,181,009.46	8,506,298.22	586,641,267.42	613,149,642.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	Medicare	1,940,423.45	133,822,341.37	140,224,083.49	8,506,298.21	586,641,267.42	613,149,642.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	OASDI (ER)	6,427,921.91	103,676,152.17	140,181,009.46	33,432,748.73	539,237,876.69	613,149,642.51
801 Duke Energy Progress, LLC	2018-Q4	Federal	56-0165465	OASDI	6,428,101.62	103,679,042.20	139,922,162.99	33,432,748.72	539,237,876.69	612,329,162.31

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1308
Second Supplemental

OASDI and SSI Program Rates & Limits 2019

Old-Age, Survivors, and Disability Insurance (OASDI)

Tax Rates (percent)	
Social Security (Old-Age, Survivors, and Disability Insurance)	
Employers and Employees, each [a]	6.20
Medicare (Hospital Insurance)	
Employers and Employees, each [a,b]	1.45
Maximum Taxable Earnings (dollars)	
Social Security	132,900
Medicare (Hospital Insurance)	No limit
Earnings Required for Work Credits (dollars)	
One Work Credit (One Quarter of Coverage)	1,360
Maximum of Four Credits a Year	5,440
Earnings Test Annual Exempt Amount (dollars)	
Under Full Retirement Age for Entire Year	17,640
For Months Before Reaching Full Retirement Age in Given Year	46,920
Beginning with Month Reaching Full Retirement Age	No limit
Maximum Monthly Social Security Benefit for Workers Retiring at Full Retirement Age (dollars)	2,861
Full Retirement Age	66
Cost-of-Living Adjustment (percent)	2.8

a. Self-employed persons pay a total of 15.3 percent—12.4 percent for OASDI and 2.9 percent for Medicare.
b. This rate does not reflect the additional 0.9 percent in Medicare taxes certain high-income taxpayers are required to pay. See IRS information on this topic.

Supplemental Security Income (SSI)

Monthly Federal Payment Standard (dollars)	
Individual	771
Couple	1,157
Cost-of-Living Adjustment (percent)	2.8
Resource Limits (dollars)	
Individual	2,000
Couple	3,000
Monthly Income Exclusions (dollars)	
Earned Income [a]	65
Unearned Income	20
Substantial Gainful Activity (SGA) Level for the Nonblind Disabled (dollars)	1,220

a. The earned income exclusion consists of the first $65 of monthly earnings, plus one-half of remaining earnings.

Office of Retirement and Disability Policy
www.ssa.gov/policy

Produced and published at U.S. taxpayer expense

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1309
Second Supplemental

Duke Energy Progress - (926) Employee Pensions and Benefits - 12 Months Ended December 31, 2018

Line No.	Account & Description	Total	
1			
2	0926000 - Empl Pensions and Benefits	$ 139,167,551	[1]
3	0926420 - Employees' Tuition Refund	899	[1]
4	0926430 - Employees'Recreation Expense	8,983	[1]
5	0926600 - Employee Benefits - Transferred	(5,967,422)	[1]
6	Total	$ 133,210,011	

[1] E-1 Item 2, Working Trial Balance

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1310
Second Supplemental

Variable Short and Long Term Pay for Duke Energy Progress - 12 Months Ended Dec 31, 2018

Line No.	Description	Total Progress	
1			
2	Level of variable short term pay	$ 70,742	[1]
3	Level of variable long term pay	17,004	[2]
4	Total (L2 + L3)	$ 87,747	
5			
6	2019 target level of variable short term pay	$ 69,054	[3]
7	2019 target level of variable long term pay	18,657	[2]
8	Total (L6 + L7)	$ 87,711	
9			
10	Adjustment to STIP	(1,241)	
11	Adjustment to LTIP	(4,674)	
12	Remaining variable short and long term pay (L8 + L10+ L11)	81,797	
13			
14	Adjustment to restate variable short and long term pay at target (L8 - L4)	$ (5,950)	

[1] NC-1310-1 - Level of Variable Short Term Pay for Duke Energy Progress - 12 Months Ended Dec 31, 2018, Line 39, Col. (c)
[2] NC-1310-3 - Variable Long Term Pay for Duke Energy Progress, Lines 6 and 13, Col. (a)
[3] NC-1310-2 - 2019 Target Level of Variable Short Term Pay for Duke Energy Progress, Line 39, Col. (c)
[3] NC-1312 - Settled Methodology excludes STIP and LTIP tied to EPS for executives and those eligible for LTIP, Line 11 & 20

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1310-1
Second Supplemental

Level of Variable Short Term Pay for Duke Energy Progress - 12 Months Ended December 31, 2018

Line No.	Description	Asset	Indirect	Liability	Other Balance Sheet	Capital	O&M	Total
1					(a)	(b)	(c)	(d)
2	Direct Charge:							
3	Duke Energy Commercial Enterprises	$ -	$ 86	$ 38	$ 125	$ 110	$ 3,008	$ 3,243
4	Duke Energy Business Services	1,957,725	951,343	131,012	3,040,081	2,829,696	7,485,974	13,355,751
5	Duke Energy Carolinas	49,707	125,170	134,323	309,201	1,681,795	3,492,564	5,483,560
6	Duke Energy Indiana	2	-	487	488	12,206	103,201	115,896
7	Duke Energy Kentucky	-	-	-	-	8	8,396	8,404
8	Duke Energy Ohio	-	-	678	678	399	44,550	45,626
9	Piedmont Natural Gas	14	-	1,767	1,781	-	9,106	10,887
10	Duke Energy Progress	234,576	3,622,776	57,692	3,915,043	10,283,443	40,588,987	54,787,474
11	Duke Energy Florida	368	4,997	35,183	40,548	14,215	245,580	300,342
12	Direct Charge Total (Sum L3 through L11)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,821,873	$ 51,981,366	$ 74,111,183
13								
14	Percentage split between capital and O&M for direct charges					22.1874%	77.8126%	100.0000%
15								
16	Service Company Allocation:							
17	Duke Energy Commercial Enterprises	$ -	$ -	$ -	$ -	$ -	$ 274	$ 274
18	Duke Energy Business Services	-	-	-	-	131,695	10,813,474	10,945,168
19	Duke Energy Carolinas	-	-	-	-	17,099	3,118,741	3,135,839
20	Duke Energy Indiana	-	-	-	-	24	1,453	1,477
21	Duke Energy Kentucky	-	-	-	-	-	-	-
22	Duke Energy Ohio	-	-	-	-	-	(233)	(233)
23	Piedmont Natural Gas	-	-	-	-	-	4,542	4,542
24	Duke Energy Progress	-	-	-	-	3,267	(919,254)	(915,987)
25	Duke Energy Florida	-	-	-	-	938	55,521	56,459
26	Service Company Allocation Total (Sum L17 through L25)	$ -	$ -	$ -	$ -	$ 153,022	$ 13,074,517	$ 13,227,539
27								
28	Percentage split between capital and O&M for allocated					1.1568%	98.8432%	100.0000%
29								
30	Total (L12 + L26)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,974,895	$ 65,055,883	$ 87,338,722
31								
32	Percentage split between capital and O&M for total					18.7114%	81.2886%	100.0000%
33								
34	Summary:							
35	Direct (L12)				$ 7,307,945	$ 14,821,873	$ 51,981,366	$ 74,111,183
36	Re-assignment of direct 'other' (-L36, Col. (a) x L14)				(7,307,945)	1,621,443	5,686,502	-
37	Allocated (L26)				0	153,022	13,074,517	13,227,539
38	Re-assignment of allocated "other"				-	0	0	(0)
39	Total (Sum L35 through L38)				$ 0	$ 16,596,338	$ 70,742,384	$ 87,338,722

Source: Duke Energy Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1310-2
Second Supplemental

2019 Target Level of Variable Short Term Pay for Duke Energy Progress

Line No.	Description	Asset	Indirect	Liability	Other Balance Sheet	Capital	O&M	Total
1					(a)	(b)	(c)	(d)
2	Direct Charge:							
3	Duke Energy Commercial Enterprises	$ -	$ 86	$ 38	$ 125	$ 110	$ 3,008	$ 3,243
4	Duke Energy Business Services	1,957,725	951,343	131,012	3,040,081	2,829,696	7,485,974	13,355,751
5	Duke Energy Carolinas	49,707	125,170	134,323	309,201	1,681,795	3,492,564	5,483,560
6	Duke Energy Indiana	2	-	487	488	12,206	103,201	115,896
7	Duke Energy Kentucky	-	-	-	-	8	8,396	8,404
8	Duke Energy Ohio	-	-	678	678	399	44,550	45,626
9	Piedmont Natural Gas	14	-	1,767	1,781	-	9,106	10,887
10	Duke Energy Progress	234,576	3,622,776	57,692	3,915,043	10,283,443	38,941,620	53,140,107
11	Duke Energy Florida	368	4,997	35,183	40,548	14,215	245,580	300,342
12	Direct Charge Total (Sum L3 through L11)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,821,873	$ 50,333,999	$ 72,463,816
13								
14	Percentage split between capital and O&M for direct charges					22.7483%	77.2517%	100.0000%
15								
16	Service Company Allocation:							
17	Duke Energy Commercial Enterprises	$ -	$ -	$ -	$ -	$ -	$ 274	$ 274
18	Duke Energy Business Services	-	-	-	-	131,695	10,813,474	10,945,168
19	Duke Energy Carolinas	-	-	-	-	17,099	3,118,741	3,135,839
20	Duke Energy Indiana	-	-	-	-	24	1,453	1,477
21	Duke Energy Kentucky	-	-	-	-	-	-	-
22	Duke Energy Ohio	-	-	-	-	-	(233)	(233)
23	Piedmont Natural Gas	-	-	-	-	-	4,542	4,542
24	Duke Energy Progress	-	-	-	-	3,267	(919,254)	(915,987)
25	Duke Energy Florida	-	-	-	-	938	55,521	56,459
26	Service Company Allocation Total (Sum L17 through L25)	$ -	$ -	$ -	$ -	$ 153,022	$ 13,074,517	$ 13,227,539
27								
28	Percentage split between capital and O&M for allocated					1.1568%	98.8432%	100.0000%
29								
30	Total (L12 + L26)	$ 2,242,393	$ 4,704,372	$ 361,180	$ 7,307,945	$ 14,974,895	$ 63,408,516	$ 85,691,355
31								
32	Percentage split between capital and O&M for total					19.1047%	80.8953%	100.0000%
33								
34	Summary:							
35	Direct (L12)				$ 7,307,945	$ 14,821,873	$ 50,333,999	$ 72,463,816
36	Re-assignment of direct 'other' (-L36, Col. (a) x L14)				(7,307,945)	1,662,433	5,645,511	-
37	Allocated (L26)				0	153,022	13,074,517	13,227,539
38	Re-assignment of allocated "other"				(0)	0	0	-
39	Total (Sum L35 through L38)				$ -	$ 16,637,328	$ 69,054,027	$ 85,691,355

Source: Duke Energy Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1310-3
Second Supplemental

Variable Long Term Pay for Duke Energy Progress

Line No.	Description	Total	Performance Awards	Phantom	Restricted Stock Units	Options
1		(a)	(b)	(c)	(d)	(e)
2	Stock-Based Compensation - Actuals - 12 Months Ended December 31, 2018					
3						
4	Grand total - gross	$ 18,456,566	$ 8,116,997	$ -	$ 10,339,568	$ -
5	Less: capital	1,452,248	214,921	-	1,237,327	-
6	Stock-based compensation, net EBIT	$ 17,004,317	$ 7,902,076	$ -	$ 9,102,241	$ -
7						
8						
9	Ongoing Stock-Based Compensation					
10						
11	Grand total - gross	$ 19,474,900	$ 7,380,304	$ -	$ 12,094,595	$ -
12	Less: capital	817,473	131,263	-	686,210	-
13	Stock-based compensation, net EBIT	$ 18,657,427	$ 7,249,041	$ -	$ 11,408,386	$ -

Note: Totals may not foot due to rounding.
Source: Duke Energy Corporate Accounting

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1311
Second Supplemental

Adjustment to Annualize Ernst & Young outside tax services contract

Line No.	Description		Total Company	DEP Allocation			Total DEP
1	E&Y outside tax services in 2019	$	7,586,926	23.2600%	[1]	$	1,764,719
2	Total costs for E&Y outside tax services in 2018		2,533,332	23.3500%	[2]		591,533
3	Adjustment to annual expense for E&Y outside tax services	$	5,053,594			$	1,173,186

[1] 2019 Service Company Cost Allocation
[2] 2018 Service Company Cost Allocation
Source - Duke Energy Progress - Corporate Services Business Support

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Normalize O&M labor expenses
For the test period ended December 31, 2018

NC-1312
Second Supplemental

Settled Methodology which excludes STIP and LTIP tied to EPS for executives and those who are eligible for LTIP

Line No.	Item	DEP Amount	
	Short Term Incentive Plan (STIP)		
1	Total Company STIP pay accrued expense associated with earnings per share (EPS)	$ 88,522	[4]
2	% of executives and LTIP eligible employees receiving STIP	6.99%	[1]
3	Total Company STIP pay accrued expense associated with earnings per share (EPS) (L1 x L2)	$ 6,190	
4	Total Company STIP accrual	341,536	[4]
5	Percentage of STIP related to EPS (L3 / L4)	1.81%	
6	STIP at target level associated with O&M expense per Company, net of Joint Owners	69,054	[2]
7	Adjustment to remove STIP related to EPS outcomes - total system (-L5 x L6)	(1,250)	
8	Executive STIP already removed in executive compensation adjustment	9	
9	Adjustment to STIP (L9 + L10)	($1,241)	
10			
11	**Long Term Incentive Plan (LTIP)**		
12	LTIP Performance Shares associated with EPS and TSR at target, net Joint Owners	$ 7,249	[3]
13		75%	[5]
14	Adjustment to remove LTIP associated with EPS and TSR - total system (-L14)	(5,437)	
15	Executive LTIP already removed in executive compensation adjustment	763	
16	Adjustment to LTIP (L18 + L19)	($4,674)	
17			
18	Total adjustment to incentive pay (L11 + L20)	($5,915)	
19			
20			
21	Based on executive compensation adjustment		
22	STIP for top five executives - DEC, net Joint Owners	$ 1,019	[1]
23	STIP EPS percentage	1.81%	
24	Exclusion percentage	50.00%	
25	Executive STIP already removed in executive comp adj	9	
26			
27	Based on executive compensation adjustment		
28	LTIP for top five executives - DEC, net Joint Owners	$ 5,239	[1]
29	LTIP EPS and TSR percentage	29.14%	[3]
30	Exclusion percentage	50.00%	
31	Executive LTIP already removed in executive comp adj	763	

[1] Per Corporate Accounting
[2] Proforma NC-1310-2 - 2019 Target Level of Variable Short Term Pay for Duke Energy Progress
[3] Proforma NC-1310-3 - Variable Long Term Pay for Duke Energy Progress
[4] Per PS Data Request 32-10
[5] Per Dorgan Settlement Exhibit 1, Schedule 3-1(g), line 11

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1900
Second Supplemental

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts operation and maintenance expenses, income taxes, depreciation and amortization expense, electric plant in service and accumulated depreciation to remove the impact of Piedmont and Progress merger costs included in the test period and the impacts in other proformas.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update

NC-1904 - Updated actuals for July - October 2019.

November update

NC-1904 - Updated actuals for November 2019.

December update

NC-1904 - Updated actuals for December 2019.

January update

NC-1904 - Updated actuals for January 2020 and formula error in April and May to sync to orginal filing

February update

NC-1904 - Updated actuals for February 2020.

Second Supplemental

NC-1903 and NC-1904 - Updated actuals for May 2020.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1900
Second Supplemental

Line No.	Description	Source	Total NC Retail		
1			Second Supplemental	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense	NC-1901	(4,039)	(4,039)	-
11	Depreciation and amortization	NC-1901	(184)	(172)	(12)
12	General taxes	NC-1901	(53)	(53)	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-1901	991	988	3
15	Amortization of investment tax credit		-	-	-
16					
17	Total electric operating expenses	Sum L8 through L15	(3,285)	(3,276)	(10)
18					
19	Operating income	L4 - L17	$ 3,285	$ 3,276	$ 10
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service	NC-1901	$ (558)	$ -	$ (558)
29	Accumulated depreciation and amortization	NC-1901	402	347	55
30	Electric plant in service, net	Sum L28 through L29	(157)	347	(504)
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment		-	-	-
35			-	-	-
36					
37	Less:				
38	Accumulated deferred taxes		-	-	-
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (157)	$ 347	$ (504)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1901
Second Supplemental

Line No.	Description	Total Utility		NC Retail Allocation	Total NC Retail
1					
2	Remove Merger Cost to Achieve - A&G	$ (5,594)	[1]	66.2120% [2]	$ (3,704)
3	Remove Merger Cost to Achieve - Customer Accts	(375)	[1]	89.2967% [3]	(335)
4	Impact to O&M (L2 + L3)	$ (5,969)			$ (4,039)
5					
6	Remove Depreciation related to Merger Transmission Plant	$ (309)	[4]	59.6699% [5]	$ (184)
7	Impact to Depreciation and Amortization (L6)	$ (309)			$ (184)
8					
9	Remove General Taxes	$ (80)	[1]	66.2120% [2]	$ (53)
10					
11	Statutory tax rate	23.1693%	[6]		23.1693%
12	Impact to income taxes ((-L4 - L7 - L9) x L11)	$ 1,473			$ 991
13					
14	Impact to operating income (-L4 - L7 - L9 - L12)	$ 4,885			$ 3,285
15					
16	Rate Base investment:				
17	Remove Tranmission Merger Electric Plant in Service	(936)	[4]	59.6699% [5]	$ (558)
18	Remove Tranmission Merger Accumulated Depreciation	673	[4]	59.6699% [5]	402
19	Impact to Rate Base investment (L17 + L18)	$ (262)			$ (157)
20					
21	Impact to rate base (L19)	$ (262)			$ (157)

[1] NC-1902 - Piedmont Cost to Achieve
[2] NC Retail Allocation Factor - LAB - Company Labor Expense
[3] NC Retail Allocation Factor - C1ALL - Number of Customers
[4] NC-1903 - Progress Cost to Achieve
[5] NC Retail Allocation Factor - DTALL - Transmission Demand
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1902
Second Supplemental

Piedmont Cost to Achieve

Line No.	Description	Total Utility 12/31/2018
1	0903000 - Cust Records and Collection Exp	$ 374,792
2	0903200 - Cust Billing and Acct	175
3	0920000 - A and G Salaries	1,215,937
4	0921100 - Employee Expenses	42,052
5	0921200 - Office Expenses	(27,999)
6	0921400 - Computer Services Expenses	35,520
7	0921540 - Computer Rent (Go Only)	26,857
8	0921980 - Office Supplies and Expenses	50,790
9	0923000 - Outside Services Employed	3,975,934
10	0926000 - Empl Pensions and Benefits	319
11	0926600 - Employee Benefits - Transferred	274,045
12	0930200 - Misc General Expenses	359
13	0930250 - Buy\Sell Transf Employee Homes	30
14	0930940 - General Expenses	27
15	0931001 - Rents - AandG	18
16	0935100 - Maint General Plant-Elec	117
17	Total O&M (Sum L1 through L16)	$ 5,968,973
18		
19	0408960 - Allocated Payroll Taxes	80,126
20		
21	Total General Taxes(L19)	$ 80,126
22		
23	Total Piedmont Cost to Achieve (L17 + L21)	$ 6,049,099

[1] Source: Corporate Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 2018

NC-1903
Second Supplemental

Progress Cost to Achieve Impacts

Line No.	Description	Plant in Service 12/31/2018	Current Rate	Calculated Annual Accrual		Actual 12ME Depr Booked	Difference
1	Impact to Income Statement Line Items						
2	Transmission - Gross Projects	$ 31,094,895 [1]	1.90% [2]	$ 590,803		287,669	$ 303,134
3	Transmission Expansion Projects (TEP) - Impairment Projects - Total	(18,560,135) [1]	1.90% [2]	(352,643)		(287,669) [4]	(64,973)
4	Balance in Plant in Service related to TEP (L2 + L3)	$ 12,534,761		$ 238,160		$ -	$ 238,160
5	Impact of Progress CTA assets to depreciation expense in NC-0802 (L4)						$ 238,160
6							
7				CURRENT		PROPOSED	
8		Plant		Calculated		Calculated	
9		in Service	Current	Annual	Proposed	Annual	Adjustment
10		12/31/2018	Rate	Accrual	Rate	Accrual	Amount
11	Transmission - Gross Projects	$ 31,094,895 [1]	1.90% [2]	$ 590,803	2.23% [3]	$ 693,416	$ 102,613
12	Transmission Expansion Projects (TEP) - Impairment Projects - Fully	(15,918,349) [1]	1.90% [2]	(302,449)	2.23% [3]	(354,979)	(52,531)
13	Transmission Expansion Projects (TEP) - Impairment Projects - Partially	(2,641,786) [1]	0.00%	-	0.00%	-	-
14	Balance in Plant in Service related to TEP (L11 + L12 + L13)	$ 12,534,761		$ 288,354		$ 338,437	$ 50,083
15	Impact of Progress CTA assets to depreciation expense in NC-2602 (L14)						$ 50,083
16							
17		Actual					
18		Net Change					
19		through			Proposed		Depr.
20		5/31/2020			Rate		Exp
21	Electric Plant in Service - Balances	$ 935,763 [1]			2.23% [3]		$ 20,868
22	Impact of Progress CTA assets to depreciation expense in NC-1001 (L21)						$ 20,868
23							
24	Impact to depreciation and amortization (L5 + L15 + L22)						$ 309,111
25							
26		Actual					
27		Net Change					
28		through					Adjustment
29		5/31/2020					Amount
30	Impact to Rate Base Line Items						
31	Electric Plant in Service - Balances	$ 935,763 [1]					$ 935,763
32	Impact of Progress CTA assets to electric plant in service in NC-1002 (L31)						$ 935,763
33							
34	Impact to electric plant in service (L32)						$ 935,763
35							
36	Accumulated Depreciation - Balances	$ (417,378) [1]					$ (417,378)
37	Impact of Progress CTA assets to accumulated depreciation in NC-1003 (L36)						$ (417,378)
38							
39		Plant		Calculated			
40		in Service	Current	Annual		12ME Depr	
41		5/31/2020	Rate	Accrual		Booked	Difference
42	Transmission - Gross Projects	$ 31,095,026 [1]	1.90% [2]	$ 590,805		294,620 [1]	$ 296,186
43	Transmission Expansion Projects (TEP) - Impairment Projects - Total	(17,624,502) [1]	1.90% [2]	(334,866)		(294,620) [1]	(40,246)
44	Balance in Plant in Service related to TEP (L42 + L43)	$ 13,470,524		$ 255,940		$ -	$ 255,940
45	Impact of Progress CTA assets to accumulated depreciation in NC-1006 (-L44)						$ (255,940)
46							
47	Impact to accumulated depreciation (L37 + L45)						$ (673,318)
48							
49	Total net plant (L34 + L47)						$ 262,445

[1] NC-1904 - Progress Cost to Achieve - Monthly Amounts
[2] NC-0802 - Adjustment to Annualize Depreciation Expense at December 31, 2018
[3] NC-2602 - Comparison of Current and Proposed Depreciation as of December 31, 2018
[4] Provided by Asset Accounting
[5] Electric plant in service and accumulated depreciation balances at 12/31/2018 related to the Transmission Expansion Projects are excluded in COSS in lines TRANSMISSION PLANT - FERC MIT REL and DPR TRANS RELATED - FERC MIT REL.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust for Merger Related Costs
For the test period ended December 31, 201

NC-1904
Second Supplementa

Progress Cost to Achieve - Monthly Amount

Line No.	Description	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019
		ACTUALS [1]								
1		a	b	c	d	e	f	g	h	i
2	Electric Plant in Service - Balances									
3	Transmission - Gross Projects	$ 31,094,895	$ 31,094,895	$ 31,095,028	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026
4	Transmission Expansion Projects (TEP) - Impairment Projects - Full	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)
5	Transmission Expansion Projects (TEP) - Impairment Projects - Partial	(2,641,786)	(2,586,748)	(2,531,711)	(2,476,674)	(2,421,637)	(2,366,600)	(2,311,562)	(2,256,525)	(2,201,488)
6	Balance in Plant in Service related to Transmission Expansion Projects (TEI	$ 12,534,761	$ 12,589,798	$ 12,644,967	$ 12,700,003	$ 12,755,040	$ 12,810,077	$ 12,865,115	$ 12,920,152	$ 12,975,189
7										
8	Accumulated Depreciation - Balances									
9	Accumulated Depreciation related to Transmission Expansion Projects (TEI	$ (1,278,080)	$ (1,302,632)	$ (1,327,184)	$ (1,351,735)	$ (1,376,287)	$ (1,400,839)	$ (1,425,390)	$ (1,449,942)	$ (1,474,494)
10										
11	Depreciation Expense - Activity									
12	Depreciation Expense on Gross Projects	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552
13	Amortization of Impairment	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)
14	Depreciation Expense related to Transmission Expansion Projects (TEI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Net Change
1		j	k	l	m	n	o	p	q	r	s = r - a
2	Electric Plant in Service - Balances										
3	Transmission - Gross Projects	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 31,095,026	$ 131
4	Transmission Expansion Projects (TEP) - Impairment Projects - Full	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	(15,918,349)	-
5	Transmission Expansion Projects (TEP) - Impairment Projects - Partial	(2,146,451)	(2,091,413)	(2,036,376)	(1,981,339)	(1,926,302)	(1,871,265)	(1,816,228)	(1,761,190)	(1,706,153)	935,632
6	Balance in Plant in Service related to Transmission Expansion Projects (TEI	$ 13,030,226	$ 13,085,264	$ 13,140,301	$ 13,195,338	$ 13,250,375	$ 13,305,412	$ 13,360,449	$ 13,415,487	$ 13,470,524	$ 935,763
7											
8	Accumulated Depreciation - Balances										
9	Accumulated Depreciation related to Transmission Expansion Projects (TEI	$ (1,499,045)	$ (1,523,597)	$ (1,548,148)	$ (1,572,700)	$ (1,597,252)	$ (1,621,803)	$ (1,646,355)	$ (1,670,907)	$ (1,695,458)	$ (417,378)
10											
11	Depreciation Expense - Activity										
12	Depreciation Expense on Gross Projects	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	$ 24,552	
13	Amortization of Impairment	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	(24,552)	
14	Depreciation Expense related to Transmission Expansion Projects (TEI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

[1] Actual amounts provided by Duke Energy Progress - Asset Accounting

Duke Energy Progress, LLC NC-2200
Docket No. E-2, Sub 1219 Second Supplemental
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts income taxes to reflect the tax impact that results from annualizing interest expense based on the end-of-period, adjusted rate base.

The impact to income taxes was determined as follows:

First, multiply rate base after all pro-forma adjustments have been made by the long-term debt ratio to calculate an adjusted long-term debt balance. Second, multiply the adjusted long-term debt balance by the end of year cost of long-term debt to calculate annualized interest expense. Third, subtract interest expense incurred during the test period from annualized interest expense and multiply the difference by the statutory tax rate.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2200
Second Supplemental

Line No.	Description	Source	Total NC Retail				
1			Second Supplemental	April	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**						
3							
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -
5							
6	Electric operating expenses:						
7	Operation and maintenance						
8	Fuel used in electric generation		-	-	-	-	-
9	Purchased power		-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-
12	General taxes		-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-
14	Income taxes	NC-2201	3,081	3,324	3,704	123	2,959
15	Amortization of investment tax credit		-	-	-	-	-
16							
17	Total electric operating expenses	Sum L8 through L15	3,081	3,324	3,704	123	2,959
18							
19	Operating income	L4 - L17	$ (3,081)	$ (3,324)	$ (3,704)	$ (123)	$ (2,959)
20							
21	Notes:						
22	Revenue: positive number increases revenue / negative number decreases revenue						
23	Expense: positive number increases expense / negative number decreases expense						
24							
25							
26	**Pro Formas Impacting Rate Base Line Items**						
27							
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-
31							
32	Add:						
33	Materials and supplies		-	-	-	-	-
34	Working capital investment		-	-	-	-	-
35							
36							
37	Less:						
38	Accumulated deferred taxes		-	-	-	-	-
39	Operating reserves		-	-	-	-	-
40							
41							
42	Construction work in progress		-	-	-	-	-
43							
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -	$ -
45							
46	Note:						
47	Rate Base: positive number increases rate base / negative number decreases rate base						

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2201
Second Supplemental

Line No.	Description	Total System		NC Retail Allocation		Total NC Retail	
1		Col [a]		Col [b]		Col [c]	
2	Rate base before pro forma adjustments	$ 14,580,739	[1]	67.6169%	[2]	$ 9,859,050	[1]
3							
4	Pro forma rate base before working capital adjustment	$ 15,196,169	[3]			$ 10,275,185	
5							
6	Long-term debt ratio	47.0000%	[4]			47.0000%	[4]
7	Calculated long-term debt (L4 x L6)	$ 7,142,200				$ 4,829,337	
8							
9	End of year cost of long-term debt	4.1074%	[4]			4.1074%	[4]
10	Annualized interest expense (L7 x L9)	$ 293,361				$ 198,362	
11							
12	Incurred interest expense	315,466	[5]	67.0949%	[6]	211,661	
13	Less interest on customer deposits	(8,643)	[7]			(7,971)	[7]
14	Net interest expense	306,823				203,690	
15							
16	Increase / <decrease> to interest costs (L10 - L14)	$ (13,462)				$ (13,300)	
17							
18	Statutory tax rate	23.1693%	[8]			23.1693%	[8]
19	Impact to income taxes (-L16 x L18)	$ 3,119				$ 3,081	
20							
21	Impact to operating income (-L19)	$ (3,119)				$ (3,081)	

[1] Smith Exhibit 1, Page 1, Line 12
[2] NC Retail Allocation Factor - Calculation: L2, Col [c] / L2, Col [a]
[3] Calculation: L4, Col [c] / L2, Col [b]
[4] Smith Exhibit 1, Page 2, Line 1
[5] Cost of Service, E-1 Item 45a, Total Other Interest Expense, Line 702
[6] NC Retail Allocation Factor - Net Book Plant
[7] Smith Exhibit 1, Page 1, Line 7
[8] NC-0104 - 2019 Tax Rate, Line 10

Duke Energy Progress, LLC — NC-2300
Docket No. E-2, Sub 1219 — Second Supplemental
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required as a result of the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 order in Docket No. M-100 Sub 137.

October Update

Reflects changes for October updates to actuals

November Update

Reflects changes for November actuals

December Update

Reflects changes for December actuals

January Update

Reflects changes for January 2020 actuals

February Update

Reflects changes for February 2020 actuals and revised E&Y Lead Lag Study

Settlement Update

Reflects changes for settlement adjustments flowing from other proformas

Second Supplemental

Reflects changes for May 2020 actuals

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2300
Second Supplemental

Line No.	Description	Source	Total NC Retail Second Supplemental Present	Proposed	April Present	Proposed	Partial Settlement Present	Proposed	Application Present	Proposed	Change Present	Proposed
1												
2	**Pro Formas Impacting Income Statement Line Items**											
3												
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5												
6	Electric operating expenses											
7	Operation and maintenance											
8	Fuel used in electric generation		-	-	-	-	-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-	-	-	-	-
14	Income taxes	NC-2301 & NC-2302	87	(249)	87	(222)	77	(234)	122	(337)	(35)	88
15	Amortization of investment tax credit		-	-	-	-	-	-	-	-	-	-
16												
17	Total electric operating expenses	Sum L8 through L15	87	(249)	87	(222)	77	(234)	122	(337)	(35)	88
18												
19	Operating income	L4 - L17	$ (87)	$ 249	$ (87)	$ 222	$ (77)	$ 234	$ (122)	$ 337	$ 35	$ (88)
20												
21	Notes:											
22	Revenue: positive number increases revenue / negative number decreases revenue											
23	Expense: positive number increases expense / negative number decreases expense											
24												
25												
26	**Pro Formas Impacting Rate Base Line Items**											
27												
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-	-	-	-	-
31												
32	Add:											
33	Materials and supplies		-	-	-	-	-	-	-	-	-	-
34	Working capital investment	NC-2302	(19,431)	55,637	(19,342)	49,639	(17,314)	52,407	(27,013)	74,407	7,582	(18,769)
35												
36												
37	Less:											
38	Accumulated deferred taxes		-	-	-	-	-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-	-	-	-	-
40												
41												
42	Construction work in progress		-	-	-	-	-	-	-	-	-	-
43												
44	Total impact to rate base	Sum L30 through L42	$ (19,431)	$ 55,637	$ (19,342)	$ 49,639	$ (17,314)	$ 52,407	$ (27,013)	$ 74,407	$ 7,582	$ (18,769)
45												
46	Note:											
47	Rate Base: positive number increases rate base / negative number decreases rate base											

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Supplemental

Line No.	Description	NC Retail – Financials: Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Iteration 1: Increase (d) = (e) - (a)	With Increase (e) = (a) + (d)	Weighted Lead Lag Days (f)
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09 [1]
2	Revenue Increase (L3)	-	438,210		433,164		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	438,210	3,790,935	433,164	3,785,889	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,478 [1]					37.39 [1]
10	Revenue Increase (L11)		1,617		1,599		37.32 [7]
11	Operation and Maintenace Expense with Increase	863,478	1,617	865,095	1,599 [3]	865,077	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	63,069 [1]					0.06 [1]
18	Revenue Increase (L19)		100,907		99,991		-20.60 [7]
19	Income Taxes with Increase	63,069	100,907	163,976	99,991 [4]	163,060	-12.61 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,926,452	102,524	3,028,975	101,589	3,028,041	24.84 [9]
24							
25	Income for Return (L3 - L23)	426,273	335,686	761,960	331,575	757,848 [5]	22.91 [9]
26	Interest Expense	197,987 [1]	1,074	199,061	-	197,987 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	228,287	334,612	562,899	331,575	559,862	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,790,935		$ 3,785,889	24.45 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,255,755 [1]	$ 55,637	$ 10,311,392		$ 10,255,755	
32							
33	Overall Rate of Return (L25 / L31)	4.16%		7.39%		7.39%	
34	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,790,935		$ 3,785,889	
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,386		$ 10,372	
40	Net Lag Days	13.87 [1]		17.62		17.61	
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 127,371	$ 55,637	$ 183,008	$ 55,269	$ 182,639	
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 132,130	$ 55,637	$ 187,768			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Supplemental

		NC Re			NC Retail		
		Financials			Iteration 2		
Line No.	Description	Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Increase (g) = (h) - (e)	With Increase (h) = (e) + (g)	Weighted Lead Lag Days (i)
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09 [1]
2	Revenue Increase (L3)	-	438,210		5,012		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	438,210	3,790,935	5,012	3,790,902	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,478 [1]					37.39 [1]
10	Revenue Increase (L11)		1,617		18	18	37.32 [7]
11	Operation and Maintenace Expense with Increase	863,478	1,617	865,095	18 [3]	865,095	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	63,069 [1]					0.06 [1]
18	Revenue Increase (L19)		100,907		910		-20.60 [7]
19	Income Taxes with Increase	63,069	100,907	163,976	910 [4]	163,970	-12.65 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,926,452	102,524	3,028,975	928	3,028,969	24.83 [9]
24							
25	Income for Return (L3 - L23)	426,273	335,686	761,960	4,084	761,932 [5]	22.91 [9]
26	Interest Expense	197,987 [1]	1,074	199,061	1,067	199,054 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	228,287	334,612	562,899	3,017	562,879	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,790,935		$ 3,790,902	24.44 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,255,755 [1]	$ 55,637	$ 10,311,392	$ 55,269	$ 10,311,024	
32							
33	Overall Rate of Return (L25 / L31)	4.16%		7.39%		7.39%	
34	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,790,935		$ 3,790,902	
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,386		$ 10,386	
40	Net Lag Days	13.87 [1]		17.62		17.62	
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 127,371	$ 55,637	$ 183,008	$ 366	$ 183,006	
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 132,130	$ 55,637	$ 187,768			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Supplemental

		NC Re			NC Retail		
		Financials			Iteration 3		
Line No.	Description	Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Increase (j) = (k) - (h)	With Increase (k) = (h) + (j)	Weighted Lead Lag Days (l)
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09 [1]
2	Revenue Increase (L3)	-	438,210		33		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	438,210	3,790,935	33	3,790,935	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,478 [1]					37.39 [1]
10	Revenue Increase (L11)		1,617		0	19	37.32 [7]
11	Operation and Maintenace Expense with Increase	863,478	1,617	865,095	0 [3]	865,095	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	63,069 [1]					0.06 [1]
18	Revenue Increase (L19)		100,907		6		-20.60 [7]
19	Income Taxes with Increase	63,069	100,907	163,976	6 [4]	163,976	-12.65 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,926,452	102,524	3,028,975	6	3,028,975	24.83 [9]
24							
25	Income for Return (L3 - L23)	426,273	335,686	761,960	27	761,959 [5]	22.91 [9]
26	Interest Expense	197,987 [1]	1,074	199,061	7	199,061 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	228,287	334,612	562,899	20	562,899	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,790,935		$ 3,790,935	24.44 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,255,755 [1]	$ 55,637	$ 10,311,392	$ 366	$ 10,311,390	
32							
33	Overall Rate of Return (L25 / L31)	4.16%		7.39%		7.39%	
34	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,790,935		$ 3,790,935	
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,386		$ 10,386	
40	Net Lag Days	13.87 [1]		17.62		17.62	
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 127,371	$ 55,637	$ 183,008	$ 2	$ 183,008	
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 132,130	$ 55,637	$ 187,768			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Supplemental

Line No.	Description	NC Re Financials: Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	NC Retail Iteration 4: Increase (m) = (n) - (k)	With Increase (n) = (k) + (m)	Weighted Lead Lag Days (o)
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09 [1]
2	Revenue Increase (L3)	-	438,210		0		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	438,210	3,790,935	0	3,790,935	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,478 [1]					37.39 [1]
10	Revenue Increase (L11)		1,617		0	19	37.32 [7]
11	Operation and Maintenace Expense with Increase	863,478	1,617	865,095	0 [3]	865,095	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	63,069 [1]					0.06 [1]
18	Revenue Increase (L19)		100,907		0		-20.60 [7]
19	Income Taxes with Increase	63,069	100,907	163,976	0 [4]	163,976	-12.65 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,926,452	102,524	3,028,975	0	3,028,975	24.83 [9]
24							
25	Income for Return (L3 - L23)	426,273	335,686	761,960	0	761,960 [5]	22.91 [9]
26	Interest Expense	197,987 [1]	1,074	199,061	0	199,061 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	228,287	334,612	562,899	0	562,899	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,790,935		$ 3,790,935	24.44 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,255,755 [1]	$ 55,637	$ 10,311,392	$ 2	$ 10,311,392	
32							
33	Overall Rate of Return (L25 / L31)	4.16%		7.39%		7.39%	
34	Target Rate of Return	7.39% [2]		7.39% [2]		7.39% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,790,935			
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,386			
40	Net Lag Days	13.87 [1]		17.62			
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 127,371	$ 55,637	$ 183,008			
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 132,130	$ 55,637	$ 187,768			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
1	**Rate Schedule Revenue**								
2	Rate Revenues	$ 3,575,788		$ 3,575,788			41.88		41.88
3	Total Revenue Lag Sales for Resale	134,915		134,915			33.73		33.73
4	Provisions For Rate Refunds	(104,546)		(104,546)			41.88		41.88
5	Forfeited Discounts	7,664		7,664			72.30		72.30
6	Miscellaneous Revenues	5,506		5,506			76.00		76.00
7	RENT - (454) - DIST PLT REL	4,466		4,466			41.63		41.63
8	RENT - (454) - DIST POLE RENTAL REV	10,901		10,901			182.00		182.00
9	RENT - (454) - TRANS PLT REL	382		382			41.63		41.63
10	RENT - (454) - ADD FAC - WHLS	-		-			0.00		0.00
11	RENT - (454) - ADD FAC - RET X LIGHTING	4,617		4,617			41.63		41.63
12	RENT - (454) - ADD FAC - LIGHTING	3,849		3,849			41.63		41.63
13	RENT - (454) - OTHER	3,413		3,413			68.21		68.21
14	OTHER ELEC REV (456) - PROD PLT REL	10,549		10,549			41.88		41.88
15	NC-0100 Annualize Retail revenues for current rates		(201,667)	(201,667)				41.88	41.88
16	NC-0300 Normalize for weather		(72,510)	(72,510)				41.88	41.88
17	NC-0400 Annualize revenues for customer growth		(10,443)	(10,443)				41.88	41.88
18	NC-0500 Eliminate unbilled revenues		11,826	11,826				41.88	41.88
19	NC-0600 Adjust costs recovered through non-fuel riders		(27,830)	(27,830)				41.88	41.88
20	NC-2900 Storm Deferral NC FMD		-	-				41.88	41.88
21	NC-3000 Adjust Other Revenue		(4,155)	(4,155)				98.96	98.96
22	Rounding		-	-				41.88	41.88
23	Revenue - Adjustments (Sum Lines 15 through 22)	-	(304,779)	(304,779)					
24									
25	Total Adjusted Revenue (L2 + L23)	$ 3,657,503	$ (304,779)	$ 3,352,725	$ -	$ 3,352,725	42.13	(0.05)	42.09
26									
27	**Operating Expenses:**								
28	Fuel Used in Electric Generation								
29	OM Prod Energy - Fuel	$ 863,120		$ 863,120			28.49		28.49
30	RECS Consumption Expense	18,522		18,522			28.49		28.49
31	NC-0200 Update fuel costs to approved rate		11,436	11,436				28.49	28.49
32	NC-0300 Normalize for weather		(20,432)	(20,432)				28.49	28.49
33	NC-0400 Annualize revenues for customer growth		(7,118)	(7,118)				28.49	28.49
34	NC-0600 Adjust costs recovered through non-fuel riders		(18,522)	(18,522)				28.49	28.49
35	NC-2900 Storm Deferral NC FMD		-	-				28.49	28.49
36	Rounding		-	-				28.49	28.49
37	Fuel Used in Electric Generation - Adjustments (Sum Lines 31 through 36)	-	(34,636)	(34,636)					
38									
39	Total Adjusted Fuel Used in Electric Generation (L29 + L37)	$ 881,642	$ (34,636)	$ 847,006	$ -	$ 847,006	28.49	0.00	28.49
40									
41	Purchased Power								
42	OM PROD PURCHASES - CAPACITY COST	$ 67,280		$ 67,280			30.29		30.29
42	OM PROD PURCHASES - ENERGY COST	365,384		365,384			30.29		30.29
43	OM DEFERRED FUEL EXPENSE	(273,901)		(273,901)			28.49		28.49
43	NC-3500 Adjust purchased power		(1,965)	(1,965)				30.29	30.29
44	Rounding		-	-					
45	Purchased Power - Adjustments (Sum Lines 43 through 44)	-	(1,965)	(1,965)					
46									
47	Total Adjusted Purchased Power (L42 + L45)	$ 158,763	$ (1,965)	$ 156,798	$ -	$ 156,798	33.40	0.04	33.44
48									

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental

Line No.	Description	NC Retail: Financials: Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Lead Lag Days: Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
49	Operation & Maintenance Expense								
50	Total Labor Expense	$ 430,295		$ 430,295			37.07		37.07
46	Pension and Benefits	76,271		76,271			13.97		13.97
47	Regulatory Commission Expense	7,038		7,038			93.25		93.25
48	Property Insurance	(526)		(526)			(222.30)		(222.30)
49	Injuries & Damages - Workman's Compensation	197		197			0.00		0.00
50	Uncollectible Accounts	8,937		8,937			0.00		0.00
51	Remaining Other Oper & Maint Expense	528,607		528,607			40.52		40.52
51	NC-0100 Annualize Retail revenues for current rates		(744)	(744)				37.32	37.32
52	NC-0200 Update fuel costs to approved rate		-	-				37.32	37.32
53	NC-0300 Normalize for weather		(268)	(268)				37.32	37.32
54	NC-0400 Annualize revenues for customer growth		(39)	(39)				37.32	37.32
55	NC-0600 Adjust costs recovered through non-fuel riders		(136,143)	(136,143)				37.32	37.32
56	NC-0700 Adjust O&M for executive compensation		(2,560)	(2,560)				37.07	37.07
57	NC-1200 Annualize O&M non-labor expenses		2,345	2,345				33.30	33.30
58	NC-1300 Normalize O&M labor expenses		(19,235)	(19,235)				37.07	37.07
59	NC-1400 Update benefits costs		(6,358)	(6,358)				13.97	13.97
60	NC-1500 Levelize nuclear refueling outage costs		(6,190)	(6,190)				40.52	40.52
61	NC-1600 Amortize rate case costs		701	701				0.00	0.00
62	NC-1700 Adjust aviation expenses		(1,657)	(1,657)				37.32	37.32
63	NC-1800 Adjust for approved regulatory assets and liabilities		1,603	1,603				0.00	0.00
64	NC-1900 Adjust for Merger Related Costs		(4,039)	(4,039)				37.32	37.32
65	NC-2000 Amortize Severance Costs		(24,140)	(24,140)				37.07	37.07
66	NC-2500 Adjust for credit card fees		5,269	5,269				40.52	40.52
67	NC-2700 Adjust vegetation management expenses		5,757	5,757				40.52	40.52
68	NC-2900 Storm Deferral NC		-	-				37.32	37.32
69	NC-3000 Adjust Other Revenue		(5)	(5)				37.32	37.32
70	NC-3100 Adjust for change in NCUC Reg Fee		(234)	(234)				93.25	93.25
71	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(6,413)	(6,413)				37.32	37.32
72	NC-3300 Adjust for CertainTeed payment Obligation		-	-				37.32	37.32
73	NC-3400 Amortize deferred balance Asheville Combined Cycle		(1,459)	(1,459)				37.32	37.32
74	NC-3700 Remove certain Settlement Items		(2,834)	(2,834)				37.32	37.32
75	NC-3900 Normalize for storm costs		9,300	9,300				37.32	37.32
76	Rounding		-	-					
77	Operation & Maintenance Expense - Adjustments (Sum Lines 51 through 72)	-	(187,341)	(187,341)					
78									
79	Total Adjusted Operation & Maintenance Expense (L50 + L77)	$ 1,050,819	$ (187,341)	$ 863,478	$ -	$ 863,478	37.32	0.08	37.39
80									
81	Depreciation and Amortization	$ 669,787		$ 669,787			0.00		0.00
82	NC-0200 Update fuel costs to approved rate		-	-				0.00	0.00
83	NC-0600 Adjust costs recovered through non-fuel riders		(58,446)	(58,446)				0.00	0.00
84	NC-0800 Annualize Depreciation on year end plant balances		41,407	41,407				0.00	0.00
85	NC-1000 Adjust for post test year additions to plant in service		68,269	68,269				0.00	0.00
86	NC-1100 Amortize deferred environmental costs		96,023	96,023				0.00	0.00
87	NC-1800 Adjust for approved regulatory assets and liabilities		(3,479)	(3,479)				0.00	0.00
88	NC-1900 Adjust for Merger Related Costs		(184)	(184)				0.00	0.00
89	NC-2600 Adjust for Depreciation for new rates		88,728	88,728				0.00	0.00
90	NC-2800 Adjust reserve for end of life nuclear costs		(1,917)	(1,917)				0.00	0.00
91	NC-2900 Storm Deferral		(1,645)	(1,645)				0.00	0.00
92	NC-3200 Reflect retirement of Asheville Steam Generating Plant		10,201	10,201				0.00	0.00
93	NC-3400 Amortize deferred balance Asheville Combined Cycle		8,970	8,970				0.00	0.00
95	Rounding		-	-					
96	Depreciation and Amortization - Adjustments (Sum Lines 82 through 95)	-	247,926	247,926					
97									
98	Total Adjusted Depreciation and Amortization (L81 + L96)	$ 669,787	$ 247,926	$ 917,713	$ -	$ 917,713	0.00	0.00	0.00
99									

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental

Line No.	Description	NC Retail: Financials: Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Lead Lag Days: Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
100	General Taxes								
101	Payroll Taxes	$ 26,288		$ 26,288			48.41		48.41
102	Property Tax	68,133		68,133			186.50		186.50
103	FED HEAVY VEHICLE USE TAX	48		48			0.00		0.00
104	ELECTRIC EXCISE TAX - SC	-		-			0.00		0.00
105	PRIVILEGE TAX	12,244		12,244			(11.97)		(11.97)
106	MISC TAX - NC	(4,517)		(4,517)			60.00		60.00
107	MISC TAX - SC & OTHER STATES	1		1			129.46		129.46
108	PUC LICENSE TAX - SC	-		-			0.00		0.00
109	NC-0600 Adjust costs recovered through non-fuel riders		(6,458)	(6,458)				137.26	137.26
110	NC-0900 Annualize property taxes on year end plant balances		4,064	4,064				186.50	186.50
111	NC-1000 Adjust for post test year additions to plant in service		5,750	5,750				186.50	186.50
112	NC-1300 Normalize O&M labor expenses		(909)	(909)				48.41	48.41
113	NC-1700 Adjust aviation expenses		(18)	(18)				48.41	48.41
114	NC-1800 Adjust for approved regulatory assets and liabilities		5	5				48.41	48.41
115	NC-1900 Adjust for Merger Related Costs		(53)	(53)				48.41	48.41
116	NC-3200 Reflect retirement of Asheville Steam Generating Plant		-	-				186.50	186.50
118	Rounding		-	-					
119	General Taxes - Adjustments (Sum Lines 109 through 118)	-	2,381	2,381					
120									
121	Total Adjusted General Tax (L101 + L119)	$ 102,197	$ 2,381	$ 104,578	$ -	$ 104,578	132.70	5.55	138.26
122									
123	Interest on Customer Deposits	$ 7,971		$ 7,971			137.50		137.50
124	Interest on Customer Deposits - Adjustments			-					
125	Rounding		-	-					
126	Total Adjusted Interest on Customer Deposits (L123 + L124)	$ 7,971	$ -	$ 7,971	$ -	$ 7,971	137.50	0.00	137.50
127									
128	Income Taxes								
129	Federal Income Tax	$ (49,091)		$ (49,091)			44.75		44.75
130	State Income Tax	(2,917)		(2,917)			44.75		44.75
131	Income Tax - Deferred	164,994		164,994			0.00		0.00
132	PF INC TAX-Adjust Income Taxes		(114,071)	(114,071)				(20.60)	(20.60)
133	NC-0600 Adjust costs recovered through non-fuel riders		63,168	63,168				0.00	0.00
134	NC-2100 Adjust NC income taxes for rate change		(2,183)	(2,183)				(20.60)	(20.60)
135	NC-2200 Synchronize interest expense		3,081	3,081				(20.60)	(20.60)
136	Rounding		-	-					
137	Income Taxes - Adjustments (Sum Lines 132 through 136)	-	(50,004)	(50,004)					
138									
139	Total Adjusted Income Taxes (L129 + L137)	$ 112,986	$ (50,004)	$ 62,982	$ 87 [5]	$ 63,069	(20.60)	20.66	0.06
140									
141	EDIT Amortization	$ -		$ -			0.00		0.00
142	NC-3700 Amortize Prot EDIT		(30,548)	(30,548)				0.00	0.00
143	Rounding		-	-					
144	EDIT Amortization (Sum Lines 142 through 143)	-	(30,548)	(30,548)					
145									
146	Total Adjusted EDIT Amortization (L141 + L144)	$ -	$ (30,548)	$ (30,548)	$ -	$ (30,548)	0.00	0.00	0.00
147									
148	Amortization of Investment Tax Credit	$ (2,134)		$ (2,134)			0.00		0.00
149	NC-0800 Annualize Depreciation on year end plant balances		(1,481)	(1,481)				0.00	0.00
150	Rounding		-	-					
151	Amort. of Investment Tax Credit - Adjustments (Sum Lines 149 through 150)	-	(1,481)	(1,481)					
152									
153	Total Adjusted Amortization of Investment Tax Credit (L148 + L151)	$ (2,134)	$ (1,481)	$ (3,614)	$ -	$ (3,614)	0.00	0.00	0.00
154									
155	Total Operating Expense (L39+L47+L79+L98+L121+L126+L139+L153)	$ 2,982,032	$ (55,667)	$ 2,926,365	$ 87	$ 2,926,452	27.48	(1.10)	26.39
156									
157	Income for Return (L25 - L155)	675,472	(249,111)	426,360	(87)	426,273	27.48	13.32	40.80
158	Interest Expense	211,661	(13,300)	198,362 [4]	(375) [4]	197,987	87.70	0.00	87.70 [1]
159	Return for Equity (L157 - L158)	463,810	(235,812)	227,998	288	228,287	0.00	0.00	0.00 [1]

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental

Line No.	Description	NC Retail – Financials: Per Books [1] (a)		Adjustments [3] (b)		Adjusted Before Change in CWC [3] (c) = (a) + (b)		Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Lead Lag Days: Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)	
160													
161	Total Requirement (L155 + L157 = L25)	$ 3,657,503				$ 3,352,725			$ 3,352,725	27.48	0.74	28.22	[6]
162													
163	RATE BASE	$ 9,859,050	[3]	$ 416,135		$ 10,275,185	[3]	$ (19,431)	$ 10,255,755				
164													
165	Overall Rate of Return (L157 / L163)	6.85%				4.15%			4.16%				
166													
167				Change									
168	Calculation of Change in Cash Working Capital (CWC) due to Adjustments	Per Books		in CWC		Adjusted							
169	Revenue Lag Days	42.13				42.09							
170	Requirement Lead Days	27.48				28.22							
171													
172	Net Lag Days (L169 - L170)	14.65				13.87							
173													
174	Annual Requirement	$ 3,657,503				$ 3,352,725							
175	Daily Requirement (L174 / 365 Days)	$ 10,021				$ 9,186							
176	Net Lag Days (L172, Rounded Per Books)	14.65				13.87							
177	Est. CWC Req. Before Sales Tax Requirement (L175 x L176)	$ 146,801				$ 127,371							
178													
179	Add: Working Capital Related to NC Sales Tax	$ 4,760	[2]			$ 4,760	[2]						
180													
181	Total Cash Working Capital Requirements (L177 + L179)	$ 151,561		$ (19,431)		$ 132,130							

Notes:
[1] NC 2305: Revised Lead Lag Study (E-1 Item 14)
[2] NC 2303 Summary
[3] Docket No. E-2, Sub 1219, Smith Exhibit 1 Rebuttal
[4] Rate Base x NC-2304-Inputs
[5] Interest Expense: - L158 x Tax Rate: 23.1693%
[6] New weighted averages calculated.

NC-2303
Second Supplemental

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the test period ended December 31, 2018
Dollars in Thousands

Revised E-1 Item 14

Line No	Description	Actual Annual Expense	Lead (Lag) Days	Weighted Amount
		[A]	[B]	[C]
	Calculation of NC Retail Amount:			
1	Total Revenue Lag	$ (3,657,503)	42.13	$ (154,105,865)
2				
3	Operation & Maintenance Expense	$ 2,091,224	33.30	$ 69,630,312
4	Depreciation and Amortization	669,787	0.00	-
5	Taxes Other Than Income Taxes	102,197	132.70	13,561,920
6	Interest on Customer Deposits	7,971	137.50	1,096,011
7	Net Income Taxes	112,986	-20.60	(2,327,337)
8	ITC	(2,134)	0.00	-
9	Income for Return	675,472	27.48	18,562,554
10	Total Requirements (Sum L3:L9)	$ 3,657,503	27.48	$ 100,523,460
11				
12	Revenue Lag Days (L1)		42.13	
13	Requirements Lead Days (-L10)		-27.48	
14	Net Lag Days (L12 + L13)		14.65	
15	Daily Requirements (Line 9, Col. A divided by 365)			$ 10,020.56
16				
17	Estimated Cash Working Capital Requirements (L14 x L15)			$ 146,801
18	Add: Cash Working Capital Related to NC Sales Tax			4,760
19	Total Cash Working Capital Requirements (L17 + L18)			$ 151,561
20				
21	**Calculation of Total Company and Jurisdictional Amounts:**			
22	NC Retail Factor			67.0949% [1]
23				
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 225,890
25				

[1] NC Retail Allocation Factor - Net Book Plant

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjustment to Cash Working Capital - Input Worksheet
For the test period ended December 31, 2018

NC-2304
Second Supplemental

Line No	Description	Rate		Ratio		Weighted	
1	Debt	4.11%	[1]	47.00%	[1]	1.9305%	[2]
2	Equity	10.30%	[1]	53.00%	[1]	5.4590%	[3]
3	Total ROR (L1 + L2)					7.3895%	
4							
5	Statutory tax rate	23.1693%	[4]				
6	Statutory regulatory fee percentage rate	0.1297%	[5]				
7	Uncollectibles rate	0.24%	[6]				

Notes:
[1] Smith Exhibit 1, Page 2
[2] Debt Rate x Debt Ratio
[3] ROE x Equity Ratio
[4] NC-0104 - 2019 Tax Rate, Line 10
[5] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate, Docket No. M-100, Sub 142
[6] NC-0105 - Development of Uncollectibles Rate

I/A

Supplemental E-1 Item 14

NC-2305
Second Supplemental

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	1	**OPERATING REVENUES:**						
	2							
	3							
Calc	4	Service Lag				15.21	A	
	5	Billing Lag						
1	6	Total Retail Sales & Billing Lag		(4,156,399,663)	(3,563,165,280)	1.66	A	
	7	Revenue - REPS		(24,719,022)	(24,719,022)			
	8	Unbilled Revenue	0440.99, 0442.19, 0442.29, 0444.99, 0445.09	13,507,473	12,096,317			
	9							
2	10	Collection Lag				25.01	A	
	11							
	12	Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17)		(4,167,611,212)	(3,575,787,985)	41.88		(149,748,041,162)
	13							
3	14	Total Revenue Lag Sales for Resale		(1,511,358,381)	(134,915,331)	33.73	A	(4,550,694,117)
	15	Provisions For Rate Refunds	0449	118,958,671	104,545,765	41.88	B	4,378,202,395
	16	Total Sales of Electricity (L12 through L14)		(5,560,010,922)	(3,606,157,551)	41.57		(149,920,532,884)
	17							
	18	Other Revenues:						
	19	Forfeited Discounts	0450100, 0450200	(8,582,371)	(7,663,772)	72.30	A	(554,090,707)
4c	20	Miscellaneous Revenues	0451100	(6,165,627)	(5,505,700)	76.00		(418,433,189)
4d	21	RENT - (454) - DIST PLT REL		(5,124,157)	(4,465,630)	41.63		(185,904,174)
4d	22	RENT - (454) - DIST POLE RENTAL REV		(12,960,572)	(10,901,069)	182.00		(1,983,994,633)
4d	23	RENT - (454) - TRANS PLT REL		(639,579)	(381,636)	41.63		(15,887,522)
4d	24	RENT - (454) - ADD FAC - WHLS		(2,806,145)	0	0.00		-
4d	25	RENT - (454) - ADD FAC - RET X LIGHTING		(5,162,072)	(4,617,085)	41.63		(192,209,244)
4d	26	RENT - (454) - ADD FAC - LIGHTING		(4,184,534)	(3,848,777)	41.63		(160,224,580)
4d	27	RENT - (454) - OTHER		(5,086,652)	(3,412,883)	68.21		(232,798,642)
	28	OTHER ELEC REV (456) - PROD PLT REL		(1,924,556)	(1,184,137)	41.88		(49,589,686)
	29	OTHER ELEC REV (456) - TRANS REL		(10,403,096)	(6,207,517)	41.88		(259,960,449)
	30	OTHER ELEC REV (456) - GEN PLT REL		0	0	41.88		-
	31	OTHER ELEC REV (456) - WH D/A		(55,825,581)	0	41.88		-
	32	OTHER ELEC REV (456) - OTHER		(548,940)	(368,310)	41.88		(15,424,225)
	33	OTHER ELEC REV (456) - REPS		(1,114,245)	(1,114,245)	41.88		(46,662,737)
	34	OTHER ELEC REV (456) - OTHER ENERGY		0	0	41.88		-
	35	OTHER ELEC REV (456) - DIST PLT REL	0456630	(1,611,605)	(1,404,491)	41.88		(58,817,730)
	36	REV - OTHER NC RETAIL SPECIFIC		(270,645)	(270,645)	41.88		(11,334,162)
	37	Total Other Revenues (L19 through L36)		(122,410,378)	(51,345,897)	81.51		(4,185,331,681)
	38							-
	39	**Utility Oper Revenues (L16 + L37)**		(5,682,421,300)	(3,657,503,448)	42.13		(154,105,864,564)
	40	ELECTRIC OPERATING REVENUE		5,682,421,300	3,657,503,448			
	41							

I/A

Supplemental E-1 Item 14

NC-2305
Second Supplemental

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	42	**OPERATION AND MAINTENANCE EXPENSE:**						
	43							
5 + 6	44	**Fuel Used in Electric Generation**						
	45	OM Prod Energy - Fuel		1,410,621,869	863,120,481	28.49	A	24,588,906,214
	46	RECS Consumption Expense		18,521,748	18,521,748	28.49	A	527,654,628
	47	**Fuel Used in Elec Gen (HFM Greenbook I/S)**	F_FUEL_USED_ELEC_GEN	**1,429,143,617**	**881,642,228**	**28.49**		**25,116,560,842**
7	48							
7	49	OM PROD PURCHASES - CAPACITY COST		109,348,837	67,279,932	30.29	A	2,037,909,147
	50	OM PROD PURCHASES - ENERGY COST		597,919,200	365,384,360	30.29	A	11,067,492,256
	51	OM DEFERRED FUEL EXPENSE	0557980	(316,590,958)	(273,901,174)	28.49	C	(7,803,001,349)
	52	**Purchased Power (Acct 555) + Def Fuel (Acct 557)**	0555XXX	**390,677,079**	**158,763,118**	**33.40**		**5,302,400,054**
	53							
	54	**Total Other O&M Excluding Fuel and Purchased Power**						
9	55							
	56	Total Labor Expense		649,874,113	430,294,724	37.07	A	15,951,025,410
8	57							
	58	Pension and Benefits	0926XXX	115,350,507	76,270,687	13.97	A	1,065,501,492
10	59							
	60	Regulatory Commission Expense	0928000	8,592,296	7,037,696	93.25	A	656,265,126
11	61							
	62	Property Insurance	0924XXX	(774,442)	(525,984)	(222.30)	A	116,926,247
15	63							
	64	Injuries & Damages - Workman's Compensation	0925980	290,241	197,125	0.00	A	-
	65							
	66	Uncollectible Accounts	0904000, 0904001	10,008,548	8,937,301	0.00	A	-
	67							
	68	Remaining Other Oper & Maint Expense		763,377,394	528,607,218	40.52	D	21,421,632,363
	69							
	70	Total O&M Excl. Fuel and Purch. Power		1,546,718,656	1,050,818,766	37.32		39,211,350,637
	71							
	72	**Total Operation and Maintenance Expense (L47 + L52 + L70)**		**3,366,539,352**	**2,091,224,112**	**33.30**		**69,630,311,534**
	73							
	74	Total Depreciation & Amortization & Property Loss		1,060,260,424	669,787,484	0.00	A	-
	75							
	76	**Taxes Other Than Income Taxes**						
	77	Payroll Taxes		39,721,091	26,288,326	48.41	A	1,272,617,860
9	78	Property Tax		101,157,752	68,132,745	186.50		12,706,756,958
13	79	FED HEAVY VEHICLE USE TAX		61,024	48,458	0.00		-
	80	ELECTRIC EXCISE TAX - SC		2,222,093	0	0.00		-
	81	PRIVILEGE TAX		16,355,581	12,243,595	(11.97)		(146,555,834)
13	82	MISC TAX - NC		-6,034,064	-4,517,029	60.00	E	(271,021,743)
	83	MISC TAX - SC & OTHER STATES		-165	949	129.46	A	122,893
	84	PUC LICENSE TAX - SC		-121,100	0	0.00	A	-

Supplemental E-1 Item 14

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018		NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	85	Taxes Other Than Income Taxes		153,362,212		102,197,044	132.70		13,561,920,134
16	86								
	87	Total Interest on Customer Deposits		8,642,928		7,970,989	137.50	A	1,096,011,021
14	88								
14	89	Federal Income Tax		(66,292,963)		(49,091,019)	44.75	A	(2,196,823,118)
	90	State Income Tax		(3,938,471)		(2,916,502)	44.75		(130,513,463)
	91	Income Tax - Deferred		220,852,977		164,993,723	0.00		-
	92	Net Income Taxes		150,621,543		112,986,202	(20.60)		(2,327,336,581)
	93								
	94	Investment of Tax Credit Adj Net	04114XX	(3,355,660)		(2,133,914)	0.00	A	-
	95								
	96	**Total Utility Operating Expenses (L72 + L74 + L85 + L87 + L92 + L94)**		4,736,070,798		2,982,031,917	27.48		81,960,906,108
	97								
	98	Interest Expense for Electric Operations		315,465,770		211,661,368	87.70	F	18,562,553,881
	99	Income for Equity Return (L100 - L198)		630,884,732		463,810,163	0.00	A	-
	100	Net Operating Income		946,350,502		675,471,531	27.48		18,562,553,881
	101								
	102	**Total Requirements (L96 + L100)**		5,682,421,300		3,657,503,448	27.48		100,523,459,988
	103								
	104								
	105	**Cash Working Capital Related to NC Sales Tax**		4,759,823	G				

	Tickmark Legend
A	Lead/lag days was obtained from Lead/Lag study performed by Ernst & Young. See the Appendix in the Duke Lead Lag Report - DEP file.
B	Revenue refund will be returned through another mechanism; number set to Revenue Lag Days to eliminate effect on Cash Working Capital.
C	Lead/lag days for fuel is being used for this line item to faciliate elimination of this item with the adjustments to cash working capital being proposed in this rate case.
D	Remaining O&M for 2018 includes both nuclear fees and other O&M lines from the 2017 lead/lag study. Lead/lag days reflected is the weighted average of the amounts for those line items from the 2017 study.
E	This expense category is a new breakout for 2018. Lead/lag days was determined based on review of activity for 2018. A majority of the balance is related to a refund which was accrued in March and received in May. As such, a 60 day lag seems reasonable.
F	See 2017 Interest Lead Days tab for calculation.
G	Cash Working Capital Related to NC Sales Tax for 2018 was calculated on Schedule 17.

Duke Energy Progress, LLC | NC-2900
Docket No. E-2, Sub 1219 | Second Supplemental
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts depreciation and amortization, and income taxes for the amortization of the deferred storm expenses related to Hurricanes Florence, Michael and Winter Storm Diego (E-2 Sub 1193). The proforma also includes the estimated impact of Hurricane Dorian from September 2019.

Working capital and accumulated deferred taxes are adjusted to reflect the regulatory asset related to the deferred storm expenses.

October update
NC-2905 - Updated Storm costs per latest estimate

November update
NC-2905 - Updated Storm costs per latest estimate

December update
NC-2905 - Updated Storm costs per latest estimate

January update
NC-2902, 2903 and 2904 - updated composite depreciation rate to exclude AMR meters and NC-2903 - Updated Column 1 Plant Balance to include Dorian Transmission capital dollars as of 9/30/2019; not captured in previous versions; NC-2905 - Updated Storm costs per latest estimate

February update
NC-2902,2903,2906,2907 - Updated Storm costs per actuals

Settlement
Remove storm from rate case

Second Supplemental
Update NC-2906 to update/remove storm accumulated depreciation in actuals from rate case

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2900
Second Supplemental

Line No.	Description	Source	Total NC Retail Second Supplemental	Application	Change
1			Second Supplemental	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**				
3					
4	Electric operating revenue		$ -	$ -	$ -
5					
6	Electric operating expenses:				
7	Operation and maintenance				
8	Fuel used in electric generation		-	-	-
9	Purchased power		-	-	-
10	Other operation and maintenance expense		-	-	-
11	Depreciation and amortization	NC-2901	(1,645)	43,717	(45,362)
12	General taxes		-	-	-
13	Interest on customer deposits		-	-	-
14	Income taxes	NC-2901	381	(10,129)	10,510
15	Amortization of investment tax credit				-
16					
17	Total electric operating expenses	Sum L8 through L15	(1,264)	33,588	(34,852)
18					
19	Operating income	L4 - L17	$ 1,264	$ (33,588)	$ 34,852
20					
21	Notes:				
22	Revenue: positive number increases revenue / negative number decreases revenue				
23	Expense: positive number increases expense / negative number decreases expense				
24					
25					
26	**Pro Formas Impacting Rate Base Line Items**				
27					
28	Electric plant in service		$ (68,639)	$ -	$ (68,639)
29	Accumulated depreciation and amortization		2,231	-	2,231
30	Electric plant in service, net	Sum L28 through L29	$ (66,408)	$ -	$ (66,408)
31					
32	Add:				
33	Materials and supplies		-	-	-
34	Working capital investment	NC-2901	-	612,045	(612,045)
35			-	-	-
36					
37	Less:				
38	Accumulated deferred taxes	NC-2901	-	(141,807)	141,807
39	Operating reserves		-	-	-
40					
41					
42	Construction work in progress		-	-	-
43					
44	Total impact to rate base	Sum L30 through L42	$ (66,408)	$ 470,238	$ (536,647)
45					
46	Note:				
47	Rate Base: positive number increases rate base / negative number decreases rate base				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2901
Second Supplemental

Line No.	Description	Distribution		Transmission [2]		Production		General Plant		Total
		Cumulative Deferred Storm Costs Balance								
1	Impact to Income Statement Line Items									
2	Projected ending balance at August 31, 2020	$ 599,483	[1]	$ 45,084	[2]	$ 3,432	[3]	$ 39	[6]	$ 648,038
3	Years to amortize	15		15		15		15		
4	Impact to depreciation and amortization (L2 / L3)	$ 39,966		$ 3,006		$ 229		$ 3		$ 43,203
5										
6	Remove storm deferral costs from rate case (-L4)	$ (39,966)		$ (3,006)		$ (229)		$ (3)		$ (43,203)
7										
8	Remove storm assets from base rates	$ (1,619)	[5]	$ (15)	[5]	$ -	[5]	$ (11)	[5]	$ (1,645)
9	Impact to depreciation and amortization expense (L4 + L6 + L8)	$ (1,619)		$ (15)		$ -		$ (11)		$ (1,645)
10										
11	Statutory tax rate	23.1693%	[4]	23.1693%	[4]	23.1693%	[4]	23.1693%	[4]	23.1693%
12	Impact to income taxes (-L9 x L11)	$ 375		$ 4		$ -		$ 2		$ 381
13										
14	Impact to operating income (-L9 - L12)	$ 1,244		$ 12		$ -		$ 8		$ 1,264
15										
16	Impact to Rate Base Line Items									
17	Impact to electric plant in service to remove storm assets from base rates	$ (67,748)	[5]	$ (678)	[5]	$ -	[5]	$ (213)		$ (68,639)
18										
19	Impact to accumulated depreciation to remove storm assets from base rates	2,203	[5]	17	[5]	-	[5]	12		2,231
20										
21	Impact to net plant (L17 + L19)	$ (65,546)		$ (662)		$ -		$ (201)		$ (66,409)
22										
23	Projected August 31, 2020 storm deferral balance for rate base (L2)	$ 599,483		$ 45,084		$ 3,432		$ 39		$ 648,038
24	Less: 1st year storm deferral amortization (-L4)	(39,966)		(3,006)		(229)		(3)		(43,203)
25	Projected storm deferral balance for rate base (L23 + L24)	$ 559,517		$ 42,078		$ 3,204		$ 37		$ 604,836
26										
27	Remove storm deferral costs from rate case (-L25)	$ (559,517)		$ (42,078)		$ (3,204)		$ (37)		$ (604,836)
28										
29	Impact to working capital investment (L25 + L27)	$ -		$ -		$ -		$ -		$ -
30										
31	Deferred tax rate	23.1693%	[4]	23.1693%	[4]	23.1693%	[4]	23.1693%		
32	Impact to accumulated deferred income tax (-L29 x L31)	$ -		$ -		$ -		$ -		$ -
33										
34	Impact to rate base (L21 + L29 + L32)	$ (65,546)		$ (662)		$ -		$ (201)		$ (66,409)

[1] NC-2902 - Projected Storm Deferral Balance-Distribution
[2] NC-2903 - Projected Storm Deferral Balance-Transmission
[3] NC-2904 - Projected Storm Deferral Balance-Production
[4] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[5] NC-2906 - NC Storm Cost Asset impacts as of May 2020
[6] NC-2907 - Projected Storm Deferral Balance-General Plant

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2902
Second Supplemental

Projected Storm Deferral Balance-Distribution

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-		343,167	214	736	344,117	344,117
2	October 31, 2018	-	-	-	-	-	-	-	28,894	446	1,538	30,879	374,996
3	November 30, 2018	-	-	-	-	-	-	-		467	1,609	2,075	377,071
4	December 31, 2018	61,182	-	-	61,182	50	171	-	31,024	489	1,685	33,418	410,489
5	January 31, 2019	52,324	125	(125)	52,200	92	317	125		511	1,762	2,806	413,295
6	February 28, 2019	62,879	107	(231)	62,648	93	321	107		515	1,774	2,809	416,104
7	March 31, 2019	62,441	128	(359)	62,082	101	348	128		518	1,786	2,882	418,986
8	April 30, 2019	62,726	127	(486)	62,239	101	347	127		522	1,799	2,895	421,882
9	May 31, 2019	62,735	128	(614)	62,121	101	347	128		525	1,811	2,912	424,794
10	June 30, 2019	62,906	128	(742)	62,164	101	347	128		529	1,824	2,928	427,722
11	July 31, 2019	63,043	128	(870)	62,173	101	347	128		533	1,836	2,945	430,667
12	August 31, 2019	63,611	128	(998)	62,612	101	348	128		536	1,849	2,963	433,630
13	September 30, 2019	63,700	130	(1,128)	62,572	101	349	130	120,798	615	2,121	124,114	557,744
14	October 31, 2019	63,383	130	(1,257)	62,126	101	348	130		695	2,394	3,667	561,411
15	November 30, 2019	63,396	129	(1,386)	62,009	101	347	129		699	2,410	3,685	565,096
16	December 31, 2019	67,351	129	(1,516)	65,836	104	357	129		704	2,426	3,719	568,815
17	January 31, 2020	67,356	137	(1,653)	65,704	107	367	137		708	2,442	3,761	572,576
18	February 29, 2020	67,356	137	(1,790)	65,567	106	366	137		713	2,458	3,781	576,357
19	March 31, 2020	67,748	137	(1,927)	65,821	106	367	137		718	2,474	3,802	580,159
20	April 30, 2020	67,748	138	(2,065)	65,683	107	367	138		722	2,490	3,824	583,983
21	May 31, 2020	67,748	138	(2,203)	65,545	106	366	138		727	2,507	3,844	587,828
22	June 30, 2020	67,748	138	(2,341)	65,408	106	366	138		732	2,523	3,865	591,692
23	July 31, 2020	67,748	138	(2,479)	65,270	106	365	138		737	2,540	3,885	595,577
24	August 31, 2020	67,748	138	(2,617)	65,132	106	364	138		742	2,556	3,906	599,483
25	Total Costs Through August 31, 2020					2,096	7,223	2,617	523,883	14,317	49,347	599,483	

Line No.	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21% Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

29 Book Depr Rate - Distribution 2.4434% [2]
30 Book Depr Rate - Transmission 1.9019% [2]
31 Book Depr Rate - Production 3.3708% [2]

[1] NC-2905 - NC Storm Cost Data as of May 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2903
Second Supplemental

Projected Storm Deferral Balance-Transmission

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-		25,742	16	55	25,813	25,813
2	October 31, 2018	-	-	-	-	-	-	-	462	32	112	606	26,419
3	November 30, 2018	-	-	-	-	-	-	-		33	113	146	26,566
4	December 31, 2018	-	-	-	-	-	-	-	139	33	114	286	26,852
5	January 31, 2019	790	-	-	790	1	2	-		33	115	151	27,003
6	February 28, 2019	983	1	(1)	982	1	5	-		34	116	156	27,159
7	March 31, 2019	541	2	(3)	538	1	4	1		34	117	157	27,316
8	April 30, 2019	553	1	(4)	550	1	3	2		34	117	157	27,473
9	May 31, 2019	577	1	(5)	572	1	3	1		34	118	157	27,630
10	June 30, 2019	582	1	(5)	577	1	3	1		34	119	158	27,788
11	July 31, 2019	577	1	(6)	571	1	3	1		35	119	159	27,947
12	August 31, 2019	583	1	(7)	575	1	3	1		35	120	160	28,106
13	September 30, 2019	613	1	(8)	605	1	3	1	14,060	44	151	14,260	42,366
14	October 31, 2019	613	1	(9)	604	1	3	1		53	182	240	42,606
15	November 30, 2019	674	1	(10)	664	1	4	1		53	183	241	42,847
16	December 31, 2019	675	1	(11)	664	1	4	1		53	184	243	43,090
17	January 31, 2020	678	1	(12)	666	1	4	1		54	185	244	43,335
18	February 29, 2020	678	1	(13)	665	1	4	1		54	186	246	43,580
19	March 31, 2020	678	1	(14)	664	1	4	1		54	187	247	43,828
20	April 30, 2020	678	1	(16)	663	1	4	1		55	188	248	44,076
21	May 31, 2020	678	1	(17)	662	1	4	1		55	189	250	44,326
22	June 30, 2020	678	1	(18)	661	1	4	1		55	190	251	44,577
23	July 31, 2020	678	1	(19)	660	1	4	1		55	191	253	44,830
24	August 31, 2020	678	1	(20)	659	1	4	1		56	192	254	45,084
25	Total Costs Through August 31, 2020					21	71	19	40,403	1,028	3,543	45,084	

Line No.	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21%		
					Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

Line No.		Rate	
29	Book Depr Rate - Distribution	2.4434%	[2]
30	Book Depr Rate - Transmission	1.9019%	[2]
31	Book Depr Rate - Production	3.3708%	[2]

[1] NC-2905 - NC Storm Cost Data as of May 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2904
Second Supplemental

Projected Storm Deferral Balance-Production

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-		3,015	2	6	3,023	3,023
2	October 31, 2018	-	-	-	-	-	-	-	-	4	13	17	3,040
3	November 30, 2018	-	-	-	-	-	-	-		4	13	17	3,057
4	December 31, 2018	-	-	-	-	-	-	-	-	4	13	17	3,074
5	January 31, 2019	-	-	-	-	-	-	-		4	13	17	3,091
6	February 28, 2019	-	-	-	-	-	-	-		4	13	17	3,108
7	March 31, 2019	-	-	-	-	-	-	-		4	13	17	3,125
8	April 30, 2019	-	-	-	-	-	-	-		4	13	17	3,142
9	May 31, 2019	-	-	-	-	-	-	-		4	13	17	3,160
10	June 30, 2019	-	-	-	-	-	-	-		4	14	17	3,177
11	July 31, 2019	-	-	-	-	-	-	-		4	14	18	3,195
12	August 31, 2019	-	-	-	-	-	-	-		4	14	18	3,212
13	September 30, 2019	-	-	-	-	-	-	-		4	14	18	3,230
14	October 31, 2019	-	-	-	-	-	-	-		4	14	18	3,248
15	November 30, 2019	-	-	-	-	-	-	-		4	14	18	3,266
16	December 31, 2019	-	-	-	-	-	-	-		4	14	18	3,284
17	January 31, 2020	-	-	-	-	-	-	-		4	14	18	3,302
18	February 29, 2020	-	-	-	-	-	-	-		4	14	18	3,321
19	March 31, 2020	-	-	-	-	-	-	-		4	14	18	3,339
20	April 30, 2020	-	-	-	-	-	-	-		4	14	18	3,357
21	May 31, 2020	-	-	-	-	-	-	-		4	14	19	3,376
22	June 30, 2020	-	-	-	-	-	-	-		4	14	19	3,395
23	July 31, 2020	-	-	-	-	-	-	-		4	15	19	3,414
24	August 31, 2020	-	-	-	-	-	-	-		4	15	19	3,432
25	Total Costs Through August 31, 2020					-	-	-	3,015	94	324	3,432	

	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21% Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

29	Book Depr Rate - Distribution	2.4434%	[2]
30	Book Depr Rate - Transmission	1.9019%	[2]
31	Book Depr Rate - Production	3.3708%	[2]

[1] NC-2905 - NC Storm Cost Data as of May 2020
[2] NC-2602 Current Depreciation Rates

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2905
Second Supplemental

NC Storm Cost Data as of May 2020

Line		Hurricane Florence - Sep 2018						Hurricane Michael - Oct 2018						Winter Storm Diego - Dec 2018						Hurricane Dorian - Sep 2019 [4]					
No.	**Description**	**System**		**Allocator**	**NC Retail**			**System**		**Allocator**	**NC Retail**			**System**		**Allocator**	**NC Retail**			**System**		**Allocator**	**NC Retail**		
1	Distr-O&M	413,650	[1]	Direct	368,245	[1]		30,102	[1]	Direct	28,894	[1]		31,600	[1]	Direct	31,024	[1]		164,450	[1]	Direct	146,319	[1]	
2	Deductible				(25,078)	[6]																	(25,521)	[6]	
3	Distr-Capital	73,260	[1]	Direct	53,282	[1]		8,944	[1]	Direct	8,944	[1]		1,483	[1]	Direct	1,483	[1]		4,222	[1]	Direct	4,041	[1]	
4																									
5	Trans-O&M	43,140	[2]	59.7%	25,742	[2]		775	[2]	59.7%	462	[2]		232	[2]	59.7%	139	[2]		23,564	[2]	59.7%	14,060	[2]	
6	Trans-Capital	968	[2]	59.7%	577	[2]														169	[2]	59.7%	101	[2]	
7																									
8	Prod-O&M	4,900	[3]	61.5%	3,015	[3]																			
9	Prod-Capital																								
10																									
11	General Plant -C	287	[4]	74.0%	213	[4]																			

[1] Information provided by Distribution Finance. Storm Cost Data as of May 2020.
[2] Information provided by Transmission Finance. Storm Cost Data as of May 2020.
[3] Information provided by Generation Finance. Storm Cost Data as of May 2020.
[4] Estimate based upon best information available. To be updated in supplemental filings.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2906
Second Supplemental

NC Storm Cost Asset impacts as of May 2020

Line No.	Description	Plant in Service 5/31/2020		Proposed Rate		Proposed Calculated Annual Accrual	
1	Impact to Income Statement Line Items						
2	Depreciation and amortization:						
3	Distribution - storm assets	$ 67,748	[1]	2.39%	[4]	$ 1,619	
4	Transmission - storm assets	678	[2]	2.23%	[5]	15	
5	Production - storm assets	-	[3]	4.15%	[5]	-	
6	General Plant - storm assets	213	[7]	5.00%	[5]	11	
7	Impact to depreciation and amortization to remove storm assets from base rates (L3 through L6)					$ (1,645)	
8							
9	Taxable income (-L7)					$ 1,645	
10	Statutory tax rate					23.1693%	[6]
11	Impact to income taxes to remove storm assets from base rates (L9 * L10)					$ 381	
12							
13	Impact to operating income to remove storm assets from base rates (L9 - L11)					$ 1,264	
14							
15		Balances at 5/31/2020				Adjustment Amount	
16	Impact to Rate Base Line Items						
17	Electric Plant in Service:						
18	Distribution - storm assets (L3)	$ 67,748				$ (67,748)	
19	Transmission - storm assets (L4)	678				(678)	
20	Production - storm assets (L5)	-				-	
21	General Plant - storm assets (L6)	213				(213)	
22	Impact to electric plant in service to remove assets from base rates (L18 through L21)					$ (68,639)	
23							
24	Accumulated Depreciation:						
25	Distribution - storm assets	$ (2,203)	[1]			$ 2,203	
26	Transmission - storm assets	(17)	[2]			17	
27	Production - storm assets	-	[3]			-	
28	General Plant - storm assets	(12)	[7]			12	
29	Impact to accumulated depreciation to remove assets from base rates (L25 through L28)					$ 2,231	
30							
31	Net electric plant:						
32	Distribution - storm assets (L18 + L25)					$ (65,545)	
33	Transmission - storm assets (L19 + L26)					(662)	
34	Production - storm assets (L20 + L27)					-	
35	General Plant - storm assets (L21 + L28)					(201)	
36	Impact to net plant to remove storm assets from base rates (L32 through L35)					$ (66,408)	
37							
38	Impact to rate base to remove storm assets from base rates (L36)					$ (66,408)	

[1] NC-2902 - Projected Storm Deferral Balance-Distribution
[2] NC-2903 - Projected Storm Deferral Balance-Transmission
[3] NC-2904 - Projected Storm Deferral Balance-Production
[4] Proposed 2018 Depreciation study - Distribution composite rate without AMR meter line
[5] Proposed 2018 Depreciation study
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] NC-2907 - Projected Storm Deferral Balance-General Plant

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Update deferred balance and amortize storm costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2907
Second Supplemental

Projected Storm Deferral Balance-General Plant

Line No.	Month and Year	Plant Bal [1]	Book Depr	Accum Depr	Rate Base	Def Cost of Cap-Debt	Def Cost of Cap-Equity	Def Depr Exp	Def O&M Exp [1]	After-Tax Ret on Def Costs-Debt	After-Tax Ret on Def Costs-Equity	Total Def Amount	Cumulative Balance
1	September 30, 2018	-		-	-	-	-			-	-	-	-
2	October 31, 2018	-	-	-	-	-	-	-	-	-	-	-	-
3	November 30, 2018	-	-	-	-	-	-	-		-	-	-	-
4	December 31, 2018	-	-	-	-	-	-	-	-	-	-	-	-
5	January 31, 2019	-	-	-	-	-	-	-		-	-	-	-
6	February 28, 2019	-	-	-	-	-	-	-		-	-	-	-
7	March 31, 2019	-	-	-	-	-	-	-		-	-	-	-
8	April 30, 2019	213	-	-	213	0	1	-		0	0	1	1
9	May 31, 2019	213	1	(1)	212	0	1	-		0	0	2	2
10	June 30, 2019	213	1	(2)	211	0	1	1		0	0	2	5
11	July 31, 2019	213	1	(3)	210	0	1	1		0	0	2	7
12	August 31, 2019	213	1	(4)	209	0	1	1		0	0	2	10
13	September 30, 2019	213	1	(4)	208	0	1	1		0	0	2	12
14	October 31, 2019	213	1	(5)	207	0	1	1		0	0	2	15
15	November 30, 2019	213	1	(6)	206	0	1	1		0	0	2	17
16	December 31, 2019	213	1	(7)	206	0	1	1		0	0	2	19
17	January 31, 2020	213	1	(8)	205	0	1	1		0	0	2	22
18	February 29, 2020	213	1	(9)	204	0	1	1		0	0	2	24
19	March 31, 2020	213	1	(10)	203	0	1	1		0	0	2	27
20	April 30, 2020	213	1	(11)	202	0	1	1		0	0	3	29
21	May 31, 2020	213	1	(12)	201	0	1	1		0	0	3	32
22	June 30, 2020	213	1	(12)	200	0	1	1		0	0	3	34
23	July 31, 2020	213	1	(13)	199	0	1	1		0	0	3	37
24	August 31, 2020	213	1	(14)	199	0	1	1		0	0	3	39
25	Total Costs Through August 31, 2020					6	19	13	-	0	1	39	

Line No.	Docket No. E-2, Sub 1142 Cost of Capital	Assumed Capital Structure	Cost Rates	Weighted Rates	Tax Rate at 21% Tax Rate	Pre-Tax	After-Tax
26	Long-Term Debt	48.0000%	4.0500%	1.9440%		1.9440%	1.4936%
27	Common Equity	52.0000%	9.9000%	5.1480%	23.1693%	6.7004%	5.1480%
28	Total		13.9500%	7.0920%		8.6444%	6.6416%

Depreciation Rates

Line No.			
29	Book Depr Rate - Distribution	2.4434%	[2]
30	Book Depr Rate - Transmission	1.9019%	[2]
31	Book Depr Rate - Production	3.3708%	[2]
32	Book Depr Rate - General Plant - 394	5.0000%	[2]

[1] NC-2905 - NC Storm Cost Data as of May 2020
[2] NC-2602 Current Depreciation Rates

Smith Exhibit 1
Second Supplemental_S

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

			North Carolina Retail Operations				
Line No.	**Description**	**Total Company Per Books** (a) **(Col. 1)**	**Per Books (Col. 2)**	**Accounting Adjustments** (c) **(Col. 3)**	**Before Proposed Increase (Col. 4)**	**Revenue and Expenses from Proposed Increase** (e) **(Col. 5)**	**After Proposed Increase (Col. 6)**
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (304,779)	$ 3,352,725	$ 389,438	$ 3,742,162
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(34,636)	847,006		847,006
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(187,341)	863,478	1,438	864,916
5	Depreciation and amortization	1,060,260	669,787	247,926	917,713		917,713
6	General taxes	153,362	102,197	2,381	104,578		104,578
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	EDIT Amortization	-	-	(30,548)	(30,548)	-	(30,548)
9	Net income taxes	150,622	112,986	(50,888)	62,098	89,671	151,769
10	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
11	Total electric operating expenses	4,736,071	2,982,032	(56,552)	2,925,480	91,109	3,016,589
12	Operating income	$ 946,351	$ 675,472	$ (248,227)	$ 427,244	$ 298,329	$ 725,573
13	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 395,635 (d)	$ 10,254,686	$ 49,457 (f)	$ 10,304,142
14	Rate of return on North Carolina retail rate base		6.85%		4.17%		7.04%

-- Some totals may not foot or compute due to rounding.

Notes:
(a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

I/A

Smith Exhibit 1
Second Supplemental_S

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

					North Carolina Retail Operations					
					Before Proposed Increase			After Proposed Increase		
Line No.	Description		Dec. 31, 2018 Amount	Pro forma Ratio	Retail Rate Base	Embedded Cost/ Return %	Operating Income	Retail Rate Base	Embedded Cost/ Return %	Operating Income
			(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)
1	Long-term debt		$ 8,108,191	48.00%	$ 4,922,249	4.11%	$ 202,178	$ 4,945,988	4.11%	$ 203,153
2	Members' equity	(a)	8,717,931	52.00%	5,332,437	4.22%	225,066	5,358,154	9.75%	522,420
3	Total		$ 16,826,122	100.00%	$ 10,254,686 (b)		$ 427,244 (c)	$ 10,304,142 (b)		725,573
4	Operating income before increase (Line 3, Column 5)									427,244
5	Additional operating income required (Line 3 minus Line 4)									298,329
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue									(226)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)									91,335
8	Additional revenue requirement									$ 389,438
9	Revenue Adjustments	(d)								$ (79,841)
10	Net Increase									$ 309,597

-- Some totals may not foot or compute due to rounding.

Notes: (a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

I/A

Smith Exhibit 1
Second Supplemental_S

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	-	(52,114)	-	(172,813)
1(D)		Annualize retail revenues for current rates- Supplemental	24,093	-	-	89	-	-	-	5,562	-	18,443
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	-	3,304	-	10,955
2(F)		Update fuel costs to proposed rate- Rebuttal	-	24,010	-	-	1,684	-	-	(5,953)	-	(19,741)
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	-	(13,653)	-	(45,273)
11(E)		Normalize for weather- Supplemental	4,882	(2,252)	-	18	-	-	-	1,649	-	5,467
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	-	534	-	1,771
4(I)		Annualize revenues for customer growth- Second Supplemental	(15,625)	(9,976)	-	(58)	-	-	-	(1,296)	-	(4,296)
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	-	63,161	-	128,547
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	(31)	-	-	-	7	-	24
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	-	556	-	1,843
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	(161)	-	-	-	37	-	124
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	-	(9,747)	(1,481)	(30,841)
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	(661)	-	-	153	-	508
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	-	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	-	(17,857)	-	(59,213)
10(I)		Adjust for post test year additions to plant in service- Second Supplemental	-	-	-	-	(2,200)	(850)	-	707	-	2,344
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	-	(24,553)	-	(81,419)
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	-	(9,949)	-	-	2,305	-	7,644
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	-	(304)	-	(1,007)
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	1,034	-	-	-	(240)	-	(794)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	-	4,542	-	15,060
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	(722)	-	181	-	126	-	416
14		Update benefits costs	-	-	-	(3,060)	-	-	-	709	-	2,351
14(D)		Update benefits costs- Supplemental	-	-	-	(3,298)	-	-	-	764	-	2,534
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	-	1,444	-	4,788
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	42	-	-	-	(10)	-	(32)
16	*	Amortize rate case costs	-	-	-	701	-	-	-	(162)	-	(539)
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	-	341	-	1,129
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	(205)	-	-	-	47	-	157

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	-	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	-	988	-	3,276
19(I)		Adjust for Merger Related Costs	-	-	-	-	(12)	-	-	3	-	10
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	-	5,414	-	17,952
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(774)	-	-	-	179	-	594
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	(2,183)	-	2,183
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	123	-	(123)
22(I)		Synchronize interest expense with end of period rate base- Updated Settlement_S	-	-	-	-	-	-	-	1,981	-	(1,981)
23	*	Adjust cash working capital	-	-	-	-	-	-	-	122	-	(122)
23(I)		Adjust cash working capital- Updated Settlement_S	-	-	-	-	-	-	-	(29)	-	29
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-	-
24(C)		Adjust coal inventory- Supplemental	-	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	-	(1,204)	-	(3,993)
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	72	-	-	-	(17)	-	(55)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	-	(20,760)	-	(68,841)
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	(873)	-	-	202	-	671
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	-	21	-	70
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	(1,826)	-	-	423	-	1,403
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	-	(10,129)	-	(33,588)
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	-	-	-	-	(45,362)	-	-	10,510	-	34,852
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	-	1,767	-	5,859
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	-	-	-	-	10,381	1,032	-	(2,644)	-	(8,769)
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	-	(1,144)	-	(3,794)
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	(4,939)	-	-	-	1,144	-	3,794
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	-	(4,565)	-	(15,138)
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	-	(7,568)	(4,624)	-	-	2,825	-	9,367

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT 0.0000% (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	-	455	-	1,510
36(E)	Correct Lead Lag- Supplemental	-	-	-	-	-	-	-	-	-	-
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	-	-	-	(30,548)	7,078	-	23,470
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	(2,834)	-	-	-	657	-	2,177
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	9,300	-	-	-	(2,155)	-	(7,145)
40	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ -	$ (74,904)	$ (1,481)	$ (319,441)
40(I)	Change from Application	13,351	11,782	-	(10,035)	(53,443)	363	(30,548)	24,016	-	71,214
41	Total adjustments	$ (304,779)	$ (34,636)	$ (1,965)	$ (187,341)	$ 247,926	$ 2,381	$ (30,548)	$ (50,888)	$ (1,481)	$ (248,227)

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	225,760	-	225,760
1(D)		Annualize retail revenues for current rates- Supplemental	-	-	-	-	-	-	-	-	(24,093)	-	(24,093)
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,311)	-	(14,311)
2(F)		Update fuel costs to proposed rate- Rebuttal	-	-	-	-	-	-	-	-	25,789	-	25,789
3	*	Normalize for weather	-	-	-	-	-	-	-	-	59,144	-	59,144
11(E)		Normalize for weather- Supplemental	-	-	-	-	-	-	-	-	(7,142)	-	(7,142)
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,314)	-	(2,314)
4(I)		Annualize revenues for customer growth- Second Supplemental	-	-	-	-	-	-	-	-	5,613	-	5,613
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,869)	-	(11,869)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,932)	(94,010)	(261,943)
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	-	-	-	-	-	(31)	5,058	5,027
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,408)	-	(2,408)
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	-	-	-	-	-	(162)	-	(162)
8		Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,290	-	40,290
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	-	-	-	-	(663)	-	(663)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,079	-	4,079
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,355	120,182	197,537
10(I)		Adjust for post test year additions to plant in service- Second Supplemental	(187,320)	195,347	-	20,220	(25,761)	-	-	2,486	(3,062)	(6,254)	(9,315)
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	106,364	29,499	135,863
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,986)	(4,208)	(14,193)
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,316	-	1,316
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	1,038	-	1,038
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,674)	-	(19,674)
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	(544)	-	(544)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,071)	-	(3,071)
14(D)		Update benefits costs- Supplemental	-	-	-	-	-	-	-	-	(3,310)	-	(3,310)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,255)	-	(6,255)
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	-	-	-	-	-	42	-	42
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	704	186	889
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	(2,670)	619	-	-	(2,051)	-	(186)	(186)
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,475)	-	(1,475)
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	-	-	-	-	-	(206)	-	(206)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,878)	(5,521)	(7,400)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,280)	31	(4,248)
19(I)		Adjust for Merger Related Costs	(558)	55	-	-	-	-	-	(504)	(12)	(45)	(57)
20	*	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,453)	1,621	(21,832)
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(23,297)	5,398	-	-	(17,899)	(777)	(1,621)	(2,398)
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,851)	-	(2,851)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22(I)		Synchronize interest expense with end of period rate base- Updated Settlement_S	-	-	-	-	-	-	-	-	2,588	-	2,588
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	160	(2,447)	(2,287)
23(I)		Adjust cash working capital- Updated Settlement_S	-	-	-	6,513	-	-	-	6,513	(37)	690	653
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24(C)		Adjust coal inventory- Supplemental	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,868)	(1,868)
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,217	-	5,217
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	-	-	-	-	-	72	-	72
26		Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,933	(8,037)	81,896
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	-	-	-	-	(876)	432	(444)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,779	-	5,779
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	-	-	-	-	(1,833)	-	(1,833)
29	*	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,879	42,594	86,473
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	(68,639)	2,231	-	(612,045)	141,807	-	-	(536,647)	(45,530)	(48,285)	(93,816)
30		Adjust other revenue	-	-	-	-	-	-	-	-	4,165	-	4,165
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(235)	-	(235)
32	*	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,654)	(2,965)	(10,619)
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,456	6,611	18,067
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,957	-	4,957
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	-	-	-	-	-	(4,957)	-	(4,957)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,776	2,230	22,006
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	(248)	(27,188)	6,299	-	-	(21,136)	(12,237)	(1,931)	(14,169)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,972)	-	(1,972)
36(E)	Correct Lead Lag- Supplemental	-	-	-	(8,580)	-	-	-	(8,580)	-	(735)	(735)
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	30,548	(7,078)	-	-	23,470	(30,661)	2,011	(28,649)
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	-	-	-	-	-	(2,844)	-	(2,844)
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	-	-	-	-	-	9,334	-	9,334
40	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 417,313	$ 79,408	$ 496,720
40(I)	Change from Application	30,535	(13,039)	(21,565)	(657,633)	130,814	-	-	(530,888)	(93,033)	(45,500)	(138,532)
41	Total adjustments	$ 611,093	$ (115,487)	$ (172,644)	$ 234,074	$ (58,470)	$ -	$ (102,930)	$ 395,635	$ 324,280	$ 33,908	$ 358,188

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(115,487)	(8,157,546)
3	Net electric plant		16,126,825	10,763,851	495,606	11,259,457
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	234,074	(141,098)
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(58,470)	(1,391,098)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 395,635	$ 10,254,686

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (179,365)	$ 9,877,155
2	Transmission Plant	2,746,389	1,643,263	264,402	1,907,665
3	Distribution Plant	6,944,764	6,052,263	433,108	6,485,371
4	General Plant	628,616	465,435	68,399	533,833
5	Intangible Plant	527,370	358,178	51,912	410,090
6	Subtotal	27,398,830	18,575,658	638,456	19,214,114
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

		Total Company	North Carolina Retail Operations		
No.	Description	Per Books (Col. 1)	Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (50,423)	$ (4,441,180)
2	Transmission Reserve	(816,198)	(488,611)	(27,693)	(516,304)
3	Distribution Reserve	(3,235,148)	(2,819,386)	26,382	(2,793,003)
4	General Reserve	(167,536)	(124,045)	(30,822)	(154,867)
5	Intangible Reserve	(322,831)	(219,260)	(32,932)	(252,192)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (115,487)	$ (8,157,546)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	North Carolina Retail Operations: Accounting Adjustments (Col. 3)		North Carolina Retail Operations: As Adjusted (Col. 4)
	Fuel Stock:					
1	Coal	$ 87,298	$ 53,347	$ (18,678)	(a)	$ 34,669
2	Oil	113,740	69,506	-		69,506
3	Total fuel stock	201,037	122,853	(18,678)		104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)		477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)		$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

I/A

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)	With Rev Incr (Col. 6)
	Investor advanced funds:						
1	Operating funds per lead-lag study	238,679 (a)	160,141 (a)	(29,080) (b)	131,061	49,457 (c)	180,518
2	Unamortized Debt	47,722	32,019	-	32,019	-	32,019
3	Regulatory Assets	(781,496)	(437,291)	263,154	(174,137)	-	(174,137)
4	Other	(10,529)	(13,453)	-	(13,453)	-	(13,453)
5	Total investor advanced funds	(505,624)	(258,584)	234,074	(24,510)	49,457	24,947
6	Less: customer deposits	(137,271)	(116,588)	-	(116,588)	-	(116,588)
7	Total working capital investment	$ (642,895)	$ (375,172)	$ 234,074	$ (141,098)	$ 49,457	$ (91,641)

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

Smith Exhibit 1
Page 4d

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Smith Exhibit 1 Supplemental Rebuttal

Line No.	Description	Ref #	SUMMARY OF PROPOSED REVENUE ADJUSTMENTS: Application	Partial Settlement	Second Supplemental	Second Supplemental_S	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(96,523)	(114,524)	(85,131)	(85,131)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(173,156)	(147,750)	(196,524)	(196,524)
6	Net Revenue Increase		$ 463,619	$ 321,573	$ 328,977	$ 309,597	$ 309,597
7							

Line No.	Description	Ref #	CHANGE IN OP INCOME: Application	Partial Settlement	Second Supplemental	Second Supplemental_S	Total Adjs [1]			CHANGE IN RATE BASE: Application	Partial Settlement	Second Supplemental	Second Supplemental_S	Total Change [2]
8														
9														
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ -	$ -	$ (154,370)			$ -	$ -	$ -	$ -	$ -
11	Update fuel costs to proposed rate	NC-0200	10,955	-	-	-	(8,786)			-	-	-	-	-
12	Normalize for weather	NC-0300	(45,273)	-	-	-	(39,806)			-	-	-	-	-
13	Annualize revenues for customer growth	NC-0400	1,771	-	(2,771)	-	(2,525)			-	-	-	-	-
14	Eliminate unbilled revenues	NC-0500	9,086	-	-	-	9,086			-	-	-	-	-
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	-	-	128,571			(1,037,885)	-	-	-	(1,037,885)
16	Adjust O&M for executive compensation	NC-0700	1,843	124	-	-	1,967			-	-	-	-	-
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	-	-	(30,333)			-	-	-	-	-
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	-	-	(3,122)			-	-	-	-	-
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	(9)	(4,732)	-	(56,870)			1,326,826	(1,507)	139,224	-	1,329,312
20	Amortize deferred environmental costs	NC-1100	(81,419)	-	-	-	(73,775)			325,675	-	-	-	295,100
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	37	1,420	-	(1,802)			-	-	-	-	-
22	Normalize O&M labor expenses	NC-1300	15,060	3,009	(3,633)	-	15,476			-	-	-	-	-
23	Update benefits costs	NC-1400	2,351	-	-	-	4,885			-	-	-	-	-
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	-	-	4,756			-	-	-	-	-
25	Amortize rate case costs	NC-1600	(539)	-	-	-	(539)			2,051	(2,051)	-	-	-
26	Adjust aviation expenses	NC-1700	1,129	157	-	-	1,287			-	-	-	-	-
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	-	-	1,438			(64,423)	-	-	-	(64,423)
28	Adjust for Merger Related Costs	NC-1900	3,276	-	2	-	3,285			347	-	(53)	-	(157)
29	Amortize Severance Costs	NC-2000	17,952	-	-	-	18,547			17,899	(16,717)	-	-	-
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	-	-	2,183			-	-	-	-	-
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(2,433)	623	978	(2,104)			-	-	-	-	-
32	Adjust cash working capital	NC-2300	(122)	17	(9)	(7)	(94)			(27,013)	3,904	(2,116)	(1,069)	(20,500)
33	Adjust coal inventory	NC-2400	-	-	-	-	-			9,641	-	-	-	(11,603)
34	Adjust for credit card fees	NC-2500	(3,993)	-	-	-	(4,048)			-	-	-	-	-
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	-	-	(68,170)			(88,728)	-	-	-	(88,728)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	-	-	(4,424)			-	-	-	-	-
37	Adjust reserve for end of life nuclear costs	NC-2800	70	1,403	-	-	1,473			-	-	-	-	-
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	34,448	7	0	1,264			470,238	(531,121)	27	-	(66,408)
39	Adjust other revenue	NC-3000	(3,188)	-	-	-	(3,188)			-	-	-	-	-
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	-	-	180			-	-	-	-	-
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	-	-	-	(2,910)			(32,730)	-	-	-	42,550
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-	-	-			-	-	-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	4,299	-	-	(5,771)			24,624	(16,124)	-	-	3,488
44	Adjust Purchased Power	NC-3500	1,510	-	-	-	1,510			-	-	-	-	-
45	Correct Lead Lag	NC-3600	-	-	-	-	-			-	-	-	-	(8,580)
46	Amortize Prot EDIT	NC-3700	-	23,470	-	-	23,470			-	23,470	-	-	23,470
47	Remove certain Settlement Items	NC-3800	-	2,177	-	-	2,177			-	-	-	-	-
48	Normalize for storm costs	NC-3900	-	(7,145)	-	-	(7,145)			-	-	-	-	-
49														
50		Adjustments	$ (319,441)	$ 59,554	$ (9,094)	$ 971	$ (248,227)			$ 926,524	$ (540,146)	$ 137,082	$ (1,069)	$ 395,635
51														
52	Operating income	[3]	675,472	675,472	675,472	675,472	675,472	Rate base	[4]	9,859,050	9,859,050	9,859,050	9,859,050	9,859,050
53	Total Adjustments		(319,441)	(240,104)	(249,198)	(248,227)	(248,227)	Total Adjustments		926,524	259,622	396,705	395,635	395,635
54	Adjusted Net Operating Income		356,031	435,367	426,273	427,244	427,244	Adjusted Rate Base		10,785,574	10,118,673	10,255,755	10,254,686	10,254,686
55														
56	Revenue Requirement Impact		417,313	(77,801)	11,880	(1,269)	324,280			79,408	(46,293)	11,749	(92)	33,908
			417,313	313,669	325,549	324,280	324,280			79,408	22,251	34,000	33,908	33,908

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

Smith Exhibit 2
Second Supplemental_S

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	NC RETAIL	Reference
1	Additional base revenue requirement	$ 389,438	Smith Second Supplemental_S Exhibit 1
2	REVISED Annual EDIT Rider 1	7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback	(85,131)	Smith Second Supplemental_S Exhibit 4
4	Regulatory Asset and Liability Rider	(2,091)	Smith Exhibit 5
5	Subtotal	(79,841)	Sum L3 - L17
6	Net Revenue Increase	$ 309,597	

I/A

DUKE ENERGY PROGRESS, LLC
Reconciliation of Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 3
Second Supplemental_S

Line No.		Item		Amount
1	Revenue requirement increase per Company application			**585,961**
2	Revenue impact of Company adjustments through Settlement			(173,156)
3	Revenue impact of supplemental updates through May			25,406
4	Revenue requirement increase per Smith Exhibit 1 Second Supplemental		**$**	**438,211**
5				
6	Changes to reflect Intervenor Settlements:			
7	Ex 1	Adjust ROE from 10.3% to 9.75		(38,526)
8	Ex 1	Adjust D/E Ratio from 53/47 to 52/48		(8,348)
9	NC2200	Adjust synchronized interest expense		(1,277)
10	NC2300	Adjust cash working capital under present rates		(88)
11	NC2300	Adjust cash working capital under proposed rates		(535)
	Rounding			-
12	Total Revenue impact of changes		$	(48,774)
13				
14	Revenue Requirement per Smith Exhibit 1 Second Supplemental_S		**$**	**389,438**

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018

NC-2200
Second Supplemental_S

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts income taxes to reflect the tax impact that results from annualizing interest expense based on the end-of-period, adjusted rate base.

The impact to income taxes was determined as follows:

First, multiply rate base after all pro-forma adjustments have been made by the long-term debt ratio to calculate an adjusted long-term debt balance. Second, multiply the adjusted long-term debt balance by the end of year cost of long-term debt to calculate annualized interest expense. Third, subtract interest expense incurred during the test period from annualized interest expense and multiply the difference by the statutory tax rate.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2200
Second Supplemental_S

Line No.	Description	Source	Total NC Retail Second Supplemental S	Second Supplemental	April	Partial Settlement	Application	Change
1			Second Supplemental S	Second Supplemental	April	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**							
3								
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -
5								
6	Electric operating expenses:							
7	Operation and maintenance							
8	Fuel used in electric generation		-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-
14	Income taxes	NC-2201	2,104	3,081	3,324	3,704	123	1,981
15	Amortization of investment tax credit		-	-	-	-	-	-
16								
17	Total electric operating expenses	Sum L8 through L15	2,104	3,081	3,324	3,704	123	1,981
18								
19	Operating income	L4 - L17	$ (2,104)	$ (3,081)	$ (3,324)	$ (3,704)	$ (123)	$ (1,981)
20								
21	Notes:							
22	Revenue: positive number increases revenue / negative number decreases revenue							
23	Expense: positive number increases expense / negative number decreases expense							
24								
25								
26	**Pro Formas Impacting Rate Base Line Items**							
27								
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-
31								
32	Add:							
33	Materials and supplies		-	-	-	-	-	-
34	Working capital investment		-	-	-	-	-	-
35								
36								
37	Less:							
38	Accumulated deferred taxes		-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-
40								
41								
42	Construction work in progress		-	-	-	-	-	-
43								
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -	$ -	$ -
45								
46	Note:							
47	Rate Base: positive number increases rate base / negative number decreases rate base							

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2201
Second Supplemental_S

Line No.	Description	Total System		NC Retail Allocation		Total NC Retail	
1		Col [a]		Col [b]		Col [c]	
2	Rate base before pro forma adjustments	$ 14,580,739	[1]	67.6169%	[2]	$ 9,859,050	[1]
3							
4	Pro forma rate base before working capital adjustment	$ 15,196,169	[3]			$ 10,275,185	
5							
6	Long-term debt ratio	48.0000%	[4]			48.0000%	[4]
7	Calculated long-term debt (L4 x L6)	$ 7,294,161				$ 4,932,089	
8							
9	End of year cost of long-term debt	4.1074%	[4]			4.1074%	[4]
10	Annualized interest expense (L7 x L9)	$ 299,603				$ 202,582	
11							
12	Incurred interest expense	315,466	[5]	67.0949%	[6]	211,661	
13	Less interest on customer deposits	(8,643)	[7]			(7,971)	[7]
14	Net interest expense	306,823				203,690	
15							
16	Increase / <decrease> to interest costs (L10 - L14)	$ (7,220)				$ (9,079)	
17							
18	Statutory tax rate	23.1693%	[8]			23.1693%	[8]
19	Impact to income taxes (-L16 x L18)	$ 1,673				$ 2,104	
20							
21	Impact to operating income (-L19)	$ (1,673)				$ (2,104)	

[1] Smith Exhibit 1, Page 1, Line 12
[2] NC Retail Allocation Factor - Calculation: L2, Col [c] / L2, Col [a]
[3] Calculation: L4, Col [c] / L2, Col [b]
[4] Smith Exhibit 1, Page 2, Line 1
[5] Cost of Service, E-1 Item 45a, Total Other Interest Expense, Line 702
[6] NC Retail Allocation Factor - Net Book Plant
[7] Smith Exhibit 1, Page 1, Line 7
[8] NC-0104 - 2019 Tax Rate, Line 10

Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required as a result of the proposed increase in rates. The adjustment is in accordance with the Commission’s March 21, 2016 order in Docket No. M-100 Sub 137.

October Update

Reflects changes for October updates to actuals

November Update

Reflects changes for November actuals

December Update

Reflects changes for December actuals

January Update

Reflects changes for January 2020 actuals

February Update

Reflects changes for February 2020 actuals and revised E&Y Lead Lag Study

Settlement Update

Reflects changes for settlement adjustments flowing from other proformas

Second Supplemental_S

Reflects changes for May 2020 actuals and incorporates changes for the Intervenor Settlements

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2300
Second Supplemental_S

Line No.	Description	Source	Present	Proposed	Present	Proposed	Present	Proposed	Present	Proposed	Present	Proposed	Present	Proposed
								Total NC Retail						
1			Second Supplemental_S		Second Supplemental		April		Partial Settlement		Application		Change	
2	**Pro Formas Impacting Income Statement Line Items**													
3														
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5														
6	Electric operating expenses:													
7	Operation and maintenance													
8	Fuel used in electric generation		-	-	-	-	-	-	-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-	-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-	-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-	-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-	-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-	-	-	-	-	-	-
14	Income taxes	NC-2301 & NC-2302	94	(226)	87	(249)	87	(222)	77	(234)	122	(337)	(29)	111
15	Amortization of investment tax credit		-	-	-	-	-	-	-	-	-	-	-	-
16														
17	Total electric operating expenses	Sum L8 through L15	94	(226)	87	(249)	87	(222)	77	(234)	122	(337)	(29)	111
18														
19	Operating income	L4 - L17	$ (94)	$ 226	$ (87)	$ 249	$ (87)	$ 222	$ (77)	$ 234	$ (122)	$ 337	$ 29	$ (111)
20														
21	Notes:													
22	Revenue: positive number increases revenue / negative number decreases revenue													
23	Expense: positive number increases expense / negative number decreases expense													
24														
25														
26	**Pro Formas Impacting Rate Base Line Items**													
27														
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-	-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-	-	-	-	-	-	-
31														
32	Add:													
33	Materials and supplies		-	-	-	-	-	-	-	-	-	-	-	-
34	Working capital investment	NC-2302	(20,500)	49,457	(19,431)	55,637	(19,342)	49,639	(17,314)	52,407	(27,013)	74,407	6,513	(24,950)
35														
36														
37	Less:													
38	Accumulated deferred taxes		-	-	-	-	-	-	-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-	-	-	-	-	-	-
40														
41														
42	Construction work in progress		-	-	-	-	-	-	-	-	-	-	-	-
43														
44	Total impact to rate base	Sum L30 through L42	$ (20,500)	$ 49,457	$ (19,431)	$ 55,637	$ (19,342)	$ 49,639	$ (17,314)	$ 52,407	$ (27,013)	$ 74,407	$ 6,513	$ (24,950)
45														
46	Note:													
47	Rate Base: positive number increases rate base / negative number decreases rate base													

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Supplemental_S

		NC Retail						
		Financials			Iteration 1			
Line No.	Description	Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Increase (d) = (e) - (a)	With Increase (e) = (a) + (d)	Weighted Lead Lag Days (f)	
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09	[1]
2	Revenue Increase (L3)	-	389,437		385,182		41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	389,437	3,742,162	385,182	3,737,907	42.07	[8]
4								
5	Operating Expenses:							
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49	[1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44	[1]
8								
9	Operation & Maintenance Expense	863,478 [1]					37.39	[1]
10	Revenue Increase (L11)		1,437		1,422		37.32	[7]
11	Operation and Maintenace Expense with Increase	863,478	1,437	864,915	1,422 [3]	864,900	37.39	[8]
12								
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00	[1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26	[1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50	[1]
16								
17	Net Income Taxes	62,098 [1]					0.39	[1]
18	Revenue Increase (L19)		89,671		88,915		-20.60	[7]
19	Income Taxes with Increase	62,098	89,671	151,769	88,915 [4]	151,013	-11.97	[8]
20								
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00	[1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00	[1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,925,480	91,108	3,016,589	90,336	3,015,817	25.02	[9]
24								
25	Income for Return (L3 - L23)	427,244	298,329	725,573	294,846	722,091 [5]	24.55	[9]
26	Interest Expense	202,178 [1]	975	203,153	-	202,178 [6]	87.70	[1]
27	Return for Equity (L25 - L26)	225,066	297,354	522,420	294,846	519,913	0.00	[1]
28								
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,742,162		$ 3,737,907	24.93	[9]
30								
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,254,686 [1]	$ 49,457	$ 10,304,142		$ 10,254,686		
32								
33	Overall Rate of Return (L25 / L31)	4.17%		7.04%		7.04%		
34	Target Rate of Return	7.04% [2]		7.04% [2]		7.04% [2]		
35								
36			Revenue	Adjusted				
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase				
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,742,162		$ 3,737,907		
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,252		$ 10,241		
40	Net Lag Days	13.75 [1]		17.14		17.13		
41								
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 126,301	$ 49,457	$ 175,758	$ 49,163	$ 175,465		
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]				
44	Total Cash Working Capital Requirements (L42 + L43)	$ 131,061	$ 49,457	$ 180,518				

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

Line No.	Description	NC Re Financials Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	NC Retail Iteration 2 Increase (g) = (h) - (e)	With Increase (h) = (e) + (g)	Weighted Lead Lag Days (i)
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09 [1]
2	Revenue Increase (L3)	-	389,437		4,229		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	389,437	3,742,162	4,229	3,742,136	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,478 [1]					37.39 [1]
10	Revenue Increase (L11)		1,437		16	16	37.32 [7]
11	Operation and Maintenace Expense with Increase	863,478	1,437	864,915	16 [3]	864,915	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	62,098 [1]					0.39 [1]
18	Revenue Increase (L19)		89,671		752		-20.60 [7]
19	Income Taxes with Increase	62,098	89,671	151,769	752 [4]	151,765	-12.01 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,925,480	91,108	3,016,589	767	3,016,584	25.01 [9]
24							
25	Income for Return (L3 - L23)	427,244	298,329	725,573	3,462	725,552 [5]	24.55 [9]
26	Interest Expense	202,178 [1]	975	203,153	969	203,147 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	225,066	297,354	522,420	2,493	522,405	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,742,162		$ 3,742,136	24.92 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,254,686 [1]	$ 49,457	$ 10,304,142	$ 49,163	$ 10,303,849	
32							
33	Overall Rate of Return (L25 / L31)	4.17%		7.04%		7.04%	
34	Target Rate of Return	7.04% [2]		7.04% [2]		7.04% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,742,162		$ 3,742,136	
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,252		$ 10,252	
40	Net Lag Days	13.75 [1]		17.14		17.14	
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 126,301	$ 49,457	$ 175,758	$ 292	$ 175,756	
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 131,061	$ 49,457	$ 180,518			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Supplemental_S

		NC Re			NC Retail			
		Financials			Iteration 3			
Line No.	Description	Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	Increase (j) = (k) - (h)	With Increase (k) = (h) + (j)	Weighted Lead Lag Days (l)	
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09	[1]
2	Revenue Increase (L3)	-	389,437		25		41.88	[7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	389,437	3,742,162	25	3,742,162	42.06	[8]
4								
5	Operating Expenses:							
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49	[1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44	[1]
8								
9	Operation & Maintenance Expense	863,478 [1]					37.39	[1]
10	Revenue Increase (L11)		1,437		0	16	37.32	[7]
11	Operation and Maintenace Expense with Increase	863,478	1,437	864,915	0 [3]	864,915	37.39	[8]
12								
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00	[1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26	[1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50	[1]
16								
17	Net Income Taxes	62,098 [1]					0.39	[1]
18	Revenue Increase (L19)		89,671		4		-20.60	[7]
19	Income Taxes with Increase	62,098	89,671	151,769	4 [4]	151,769	-12.01	[8]
20								
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00	[1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00	[1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,925,480	91,108	3,016,589	5	3,016,588	25.01	[9]
24								
25	Income for Return (L3 - L23)	427,244	298,329	725,573	21	725,573 [5]	24.55	[9]
26	Interest Expense	202,178 [1]	975	203,153	6	203,153 [6]	87.70	[1]
27	Return for Equity (L25 - L26)	225,066	297,354	522,420	15	522,420	0.00	[1]
28								
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,742,162		$ 3,742,162	24.92	[9]
30								
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,254,686 [1]	$ 49,457	$ 10,304,142	$ 292	$ 10,304,141		
32								
33	Overall Rate of Return (L25 / L31)	4.17%		7.04%		7.04%		
34	Target Rate of Return	7.04% [2]		7.04% [2]		7.04% [2]		
35								
36			Revenue	Adjusted				
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase				
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,742,162		$ 3,742,162		
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,252		$ 10,252		
40	Net Lag Days	13.75 [1]		17.14		17.14		
41								
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 126,301	$ 49,457	$ 175,758	$ 2	$ 175,758		
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]				
44	Total Cash Working Capital Requirements (L42 + L43)	$ 131,061	$ 49,457	$ 180,518				

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

Line No.	Description	NC Re Financials: Adjusted with CWC (a)	Revenue Increase (b) = (c) - (a)	Adjusted w/Increase (c) = (n)	NC Retail Iteration 4: Increase (m) = (n) - (k)	With Increase (n) = (k) + (m)	Weighted Lead Lag Days (o)
1	Total Adjusted Present Revenue	$ 3,352,725 [1]					42.09 [1]
2	Revenue Increase (L3)	-	389,437		0		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,352,725	389,437	3,742,162	0	3,742,162	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	847,006 [1]	-	847,006		847,006	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,478 [1]					37.39 [1]
10	Revenue Increase (L11)		1,437		0	16	37.32 [7]
11	Operation and Maintenace Expense with Increase	863,478	1,437	864,915	0 [3]	864,915	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	917,713 [1]	-	917,713		917,713	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	62,098 [1]					0.39 [1]
18	Revenue Increase (L19)		89,671		0		-20.60 [7]
19	Income Taxes with Increase	62,098	89,671	151,769	0 [4]	151,769	-12.01 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,925,480	91,108	3,016,589	0	3,016,589	25.01 [9]
24							
25	Income for Return (L3 - L23)	427,244	298,329	725,573	0	725,573 [5]	24.55 [9]
26	Interest Expense	202,178 [1]	975	203,153	0	203,153 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	225,066	297,354	522,420	0	522,420	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,352,725		$ 3,742,162		$ 3,742,162	24.92 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,254,686 [1]	$ 49,457	$ 10,304,142	$ 2	$ 10,304,142	
32							
33	Overall Rate of Return (L25 / L31)	4.17%		7.04%		7.04%	
34	Target Rate of Return	7.04% [2]		7.04% [2]		7.04% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,352,725		$ 3,742,162			
39	Daily Requirement (L38 / 365 Days)	$ 9,186		$ 10,252			
40	Net Lag Days	13.75 [1]		17.14			
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 126,301	$ 49,457	$ 175,758			
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 131,061	$ 49,457	$ 180,518			

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
1	**Rate Schedule Revenue**								
2	Rate Revenues	$ 3,575,788		$ 3,575,788			41.88		41.88
3	Total Revenue Lag Sales for Resale	134,915		134,915			33.73		33.73
4	Provisions For Rate Refunds	(104,546)		(104,546)			41.88		41.88
5	Forfeited Discounts	7,664		7,664			72.30		72.30
6	Miscellaneous Revenues	5,506		5,506			76.00		76.00
7	RENT - (454) - DIST PLT REL	4,466		4,466			41.63		41.63
8	RENT - (454) - DIST POLE RENTAL REV	10,901		10,901			182.00		182.00
9	RENT - (454) - TRANS PLT REL	382		382			41.63		41.63
10	RENT - (454) - ADD FAC - WHLS	-		-			0.00		0.00
11	RENT - (454) - ADD FAC - RET X LIGHTING	4,617		4,617			41.63		41.63
12	RENT - (454) - ADD FAC - LIGHTING	3,849		3,849			41.63		41.63
13	RENT - (454) - OTHER	3,413		3,413			68.21		68.21
14	OTHER ELEC REV (456) - PROD PLT REL	10,549		10,549			41.88		41.88
15	NC-0100 Annualize Retail revenues for current rates		(201,667)	(201,667)				41.88	41.88
16	NC-0300 Normalize for weather		(72,510)	(72,510)				41.88	41.88
17	NC-0400 Annualize revenues for customer growth		(10,443)	(10,443)				41.88	41.88
18	NC-0500 Eliminate unbilled revenues		11,826	11,826				41.88	41.88
19	NC-0600 Adjust costs recovered through non-fuel riders		(27,830)	(27,830)				41.88	41.88
20	NC-2900 Storm Deferral NC FMD		-	-				41.88	41.88
21	NC-3000 Adjust Other Revenue		(4,155)	(4,155)				98.96	98.96
22	Rounding		-	-				41.88	41.88
23	Revenue - Adjustments (Sum Lines 15 through 22)	-	(304,779)	(304,779)					
24									
25	Total Adjusted Revenue (L2 + L23)	$ 3,657,503	$ (304,779)	$ 3,352,725	$ -	$ 3,352,725	42.13	(0.05)	42.09
26									
27	**Operating Expenses:**								
28	Fuel Used in Electric Generation								
29	OM Prod Energy - Fuel	$ 863,120		$ 863,120			28.49		28.49
30	RECS Consumption Expense	18,522		18,522			28.49		28.49
31	NC-0200 Update fuel costs to approved rate		11,436	11,436				28.49	28.49
32	NC-0300 Normalize for weather		(20,432)	(20,432)				28.49	28.49
33	NC-0400 Annualize revenues for customer growth		(7,118)	(7,118)				28.49	28.49
34	NC-0600 Adjust costs recovered through non-fuel riders		(18,522)	(18,522)				28.49	28.49
35	NC-2900 Storm Deferral NC FMD		-	-				28.49	28.49
36	Rounding		-	-				28.49	28.49
37	Fuel Used in Electric Generation - Adjustments (Sum Lines 31 through 36)	-	(34,636)	(34,636)					
38									
39	Total Adjusted Fuel Used in Electric Generation (L29 + L37)	$ 881,642	$ (34,636)	$ 847,006	$ -	$ 847,006	28.49	0.00	28.49
40									
41	Purchased Power								
42	OM PROD PURCHASES - CAPACITY COST	$ 67,280		$ 67,280			30.29		30.29
42	OM PROD PURCHASES - ENERGY COST	365,384		365,384			30.29		30.29
43	OM DEFERRED FUEL EXPENSE	(273,901)		(273,901)			28.49		28.49
43	NC-3500 Adjust purchased power		(1,965)	(1,965)				30.29	30.29
44	Rounding		-	-					
45	Purchased Power - Adjustments (Sum Lines 43 through 44)	-	(1,965)	(1,965)					
46									
47	Total Adjusted Purchased Power (L42 + L45)	$ 158,763	$ (1,965)	$ 156,798	$ -	$ 156,798	33.40	0.04	33.44
48									

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental_S

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
49	Operation & Maintenance Expense								
50	Total Labor Expense	$ 430,295		$ 430,295			37.07		37.07
46	Pension and Benefits	76,271		76,271			13.97		13.97
47	Regulatory Commission Expense	7,038		7,038			93.25		93.25
48	Property Insurance	(526)		(526)			(222.30)		(222.30)
49	Injuries & Damages - Workman's Compensation	197		197			0.00		0.00
50	Uncollectible Accounts	8,937		8,937			0.00		0.00
51	Remaining Other Oper & Maint Expense	528,607		528,607			40.52		40.52
51	NC-0100 Annualize Retail revenues for current rates		(744)	(744)				37.32	37.32
52	NC-0200 Update fuel costs to approved rate		-	-				37.32	37.32
53	NC-0300 Normalize for weather		(268)	(268)				37.32	37.32
54	NC-0400 Annualize revenues for customer growth		(39)	(39)				37.32	37.32
55	NC-0600 Adjust costs recovered through non-fuel riders		(136,143)	(136,143)				37.32	37.32
56	NC-0700 Adjust O&M for executive compensation		(2,560)	(2,560)				37.07	37.07
57	NC-1200 Annualize O&M non-labor expenses		2,345	2,345				33.30	33.30
58	NC-1300 Normalize O&M labor expenses		(19,235)	(19,235)				37.07	37.07
59	NC-1400 Update benefits costs		(6,358)	(6,358)				13.97	13.97
60	NC-1500 Levelize nuclear refueling outage costs		(6,190)	(6,190)				40.52	40.52
61	NC-1600 Amortize rate case costs		701	701				0.00	0.00
62	NC-1700 Adjust aviation expenses		(1,657)	(1,657)				37.32	37.32
63	NC-1800 Adjust for approved regulatory assets and liabilities		1,603	1,603				0.00	0.00
64	NC-1900 Adjust for Merger Related Costs		(4,039)	(4,039)				37.32	37.32
65	NC-2000 Amortize Severance Costs		(24,140)	(24,140)				37.07	37.07
66	NC-2500 Adjust for credit card fees		5,269	5,269				40.52	40.52
67	NC-2700 Adjust vegetation management expenses		5,757	5,757				40.52	40.52
68	NC-2900 Storm Deferral NC		-	-				37.32	37.32
69	NC-3000 Adjust Other Revenue		(5)	(5)				37.32	37.32
70	NC-3100 Adjust for change in NCUC Reg Fee		(234)	(234)				93.25	93.25
71	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(6,413)	(6,413)				37.32	37.32
72	NC-3300 Adjust for CertainTeed payment Obligation		-	-				37.32	37.32
73	NC-3400 Amortize deferred balance Asheville Combined Cycle		(1,459)	(1,459)				37.32	37.32
74	NC-3700 Remove certain Settlement Items		(2,834)	(2,834)				37.32	37.32
75	NC-3900 Normalize for storm costs		9,300	9,300				37.32	37.32
76	Rounding		-	-					
77	Operation & Maintenance Expense - Adjustments (Sum Lines 51 through 72)	-	(187,341)	(187,341)					
78									
79	Total Adjusted Operation & Maintenance Expense (L50 + L77)	$ 1,050,819	$ (187,341)	$ 863,478	$ -	$ 863,478	37.32	0.08	37.39
80									
81	Depreciation and Amortization	$ 669,787		$ 669,787			0.00		0.00
82	NC-0200 Update fuel costs to approved rate		-	-				0.00	0.00
83	NC-0600 Adjust costs recovered through non-fuel riders		(58,446)	(58,446)				0.00	0.00
84	NC-0800 Annualize Depreciation on year end plant balances		41,407	41,407				0.00	0.00
85	NC-1000 Adjust for post test year additions to plant in service		68,269	68,269				0.00	0.00
86	NC-1100 Amortize deferred environmental costs		96,023	96,023				0.00	0.00
87	NC-1800 Adjust for approved regulatory assets and liabilities		(3,479)	(3,479)				0.00	0.00
88	NC-1900 Adjust for Merger Related Costs		(184)	(184)				0.00	0.00
89	NC-2600 Adjust for Depreciation for new rates		88,728	88,728				0.00	0.00
90	NC-2800 Adjust reserve for end of life nuclear costs		(1,917)	(1,917)				0.00	0.00
91	NC-2900 Storm Deferral		(1,645)	(1,645)				0.00	0.00
92	NC-3200 Reflect retirement of Asheville Steam Generating Plant		10,201	10,201				0.00	0.00
93	NC-3400 Amortize deferred balance Asheville Combined Cycle		8,970	8,970				0.00	0.00
95	Rounding		-	-					
96	Depreciation and Amortization - Adjustments (Sum Lines 82 through 95)	-	247,926	247,926					
97									
98	Total Adjusted Depreciation and Amortization (L81 + L96)	$ 669,787	$ 247,926	$ 917,713	$ -	$ 917,713	0.00	0.00	0.00
99									

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental_S

		NC Retail							
		Financials					Lead Lag Days		
Line No.	Description	Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
100	General Taxes								
101	Payroll Taxes	$ 26,288		$ 26,288			48.41		48.41
102	Property Tax	68,133		68,133			186.50		186.50
103	FED HEAVY VEHICLE USE TAX	48		48			0.00		0.00
104	ELECTRIC EXCISE TAX - SC	-		-			0.00		0.00
105	PRIVILEGE TAX	12,244		12,244			(11.97)		(11.97)
106	MISC TAX - NC	(4,517)		(4,517)			60.00		60.00
107	MISC TAX - SC & OTHER STATES	1		1			129.46		129.46
108	PUC LICENSE TAX - SC	-		-			0.00		0.00
109	NC-0600 Adjust costs recovered through non-fuel riders		(6,458)	(6,458)				137.26	137.26
110	NC-0900 Annualize property taxes on year end plant balances		4,064	4,064				186.50	186.50
111	NC-1000 Adjust for post test year additions to plant in service		5,750	5,750				186.50	186.50
112	NC-1300 Normalize O&M labor expenses		(909)	(909)				48.41	48.41
113	NC-1700 Adjust aviation expenses		(18)	(18)				48.41	48.41
114	NC-1800 Adjust for approved regulatory assets and liabilities		5	5				48.41	48.41
115	NC-1900 Adjust for Merger Related Costs		(53)	(53)				48.41	48.41
116	NC-3200 Reflect retirement of Asheville Steam Generating Plant		-	-				186.50	186.50
118	Rounding		-	-					
119	General Taxes - Adjustments (Sum Lines 109 through 118)	-	2,381	2,381					
120									
121	Total Adjusted General Tax (L101 + L119)	$ 102,197	$ 2,381	$ 104,578	$ -	$ 104,578	132.70	5.55	138.26
122									
123	Interest on Customer Deposits	$ 7,971		$ 7,971			137.50		137.50
124	Interest on Customer Deposits - Adjustments			-					
125	Rounding		-	-					
126	Total Adjusted Interest on Customer Deposits (L123 + L124)	$ 7,971	$ -	$ 7,971	$ -	$ 7,971	137.50	0.00	137.50
127									
128	Income Taxes								
129	Federal Income Tax	$ (49,091)		$ (49,091)			44.75		44.75
130	State Income Tax	(2,917)		(2,917)			44.75		44.75
131	Income Tax - Deferred	164,994		164,994			0.00		0.00
132	PF INC TAX-Adjust Income Taxes		(114,071)	(114,071)				(20.60)	(20.60)
133	NC-0600 Adjust costs recovered through non-fuel riders		63,168	63,168				0.00	0.00
134	NC-2100 Adjust NC income taxes for rate change		(2,183)	(2,183)				(20.60)	(20.60)
135	NC-2200 Synchronize interest expense		2,104	2,104				(20.60)	(20.60)
136	Rounding		-	-					
137	Income Taxes - Adjustments (Sum Lines 132 through 136)	-	(50,982)	(50,982)					
138									
139	Total Adjusted Income Taxes (L129 + L137)	$ 112,986	$ (50,982)	$ 62,004	$ 94 [5]	$ 62,098	(20.60)	20.98	0.39
140									
141	EDIT Amortization	$ -		$ -			0.00		0.00
142	NC-3700 Amortize Prot EDIT		(30,548)	(30,548)				0.00	0.00
143	Rounding		-	-					
144	EDIT Amortization (Sum Lines 142 through 143)	-	(30,548)	(30,548)					
145									
146	Total Adjusted EDIT Amortization (L141 + L144)	$ -	$ (30,548)	$ (30,548)	$ -	$ (30,548)	0.00	0.00	0.00
147									
148	Amortization of Investment Tax Credit	$ (2,134)		$ (2,134)			0.00		0.00
149	NC-0800 Annualize Depreciation on year end plant balances		(1,481)	(1,481)				0.00	0.00
150	Rounding		-	-					
151	Amort. of Investment Tax Credit - Adjustments (Sum Lines 149 through 150)	-	(1,481)	(1,481)					
152									
153	Total Adjusted Amortization of Investment Tax Credit (L148 + L151)	$ (2,134)	$ (1,481)	$ (3,614)	$ -	$ (3,614)	0.00	0.00	0.00
154									
155	Total Operating Expense (L39+L47+L79+L98+L121+L126+L139+L153)	$ 2,982,032	$ (56,645)	$ 2,925,387	$ 94	$ 2,925,480	27.48	(1.08)	26.40
156									
157	Income for Return (L25 - L155)	675,472	(248,133)	427,338	(94)	427,244	27.48	14.09	41.57
158	Interest Expense	211,661	(9,079)	202,582 [4]	(404) [4]	202,178	87.70	0.00	87.70 [1]
159	Return for Equity (L157 - L158)	463,810	(239,054)	224,756	311	225,066	0.00	0.00	0.00 [1]

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

		NC Retail													
		Financials								Lead Lag Days					
Line No.	Description	Per Books (a)	[1]	Adjustments (b)	[3]	Adjusted Before Change in CWC (c) = (a) + (b)	[3]	Change in CWC (d)		Adjusted with CWC (e) = (c) + (d)	Per Books (f)	[1]	Adjustments (g)	[1]	Adjusted Before Increase (h) = (f) + (g)	[6]
160															
161	Total Requirement (L155 + L157 = L25)	$ 3,657,503				$ 3,352,725				$ 3,352,725	27.48		0.85		28.34	[6]
162															
163	RATE BASE	$ 9,859,050	[3]	$ 416,135		$ 10,275,185	[3]	$ (20,500)		$ 10,254,686					
164															
165	Overall Rate of Return (L157 / L163)	6.85%				4.16%				4.17%					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Supplemental_S

		NC Retail														
		Financials									Lead Lag Days					
Line No.	Description	Per Books (a)	[1]	Adjustments (b)	[3]	Adjusted Before Change in CWC (c) = (a) + (b)		[3]	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Per Books (f)	[1]	Adjustments (g)	[1]	Adjusted Before Increase (h) = (f) + (g)	[6]
166																
167				Change												
168	Calculation of Change in Cash Working Capital (CWC) due to Adjustments	Per Books		in CWC		Adjusted										
169	Revenue Lag Days	42.13				42.09										
170	Requirement Lead Days	27.48				28.34										
171																
172	Net Lag Days (L169 - L170)	14.65				13.75										
173																
174	Annual Requirement	$ 3,657,503				$ 3,352,725										
175	Daily Requirement (L174 / 365 Days)	$ 10,021				$ 9,186										
176	Net Lag Days (L172, Rounded Per Books)	14.65				13.75										
177	Est. CWC Req. Before Sales Tax Requirement (L175 x L176)	$ 146,801				$ 126,301										
178																
179	Add: Working Capital Related to NC Sales Tax	$ 4,760	[2]			$ 4,760		[2]								
180																
181	Total Cash Working Capital Requirements (L177 + L179)	$ 151,561		$ (20,500)		$ 131,061										

Notes:
[1] NC 2305: Revised Lead Lag Study (E-1 Item 14)
[2] NC 2303 Summary
[3] Docket No. E-2, Sub 1219, Smith Exhibit 1 Rebuttal
[4] Rate Base x NC-2304-Inputs
[5] Interest Expense: - L158 x Tax Rate: 23.1693%
[6] New weighted averages calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the test period ended December 31, 2018
Dollars in Thousands

Revised E-1 Item 14

Line No	Description	Actual Annual Expense	Lead (Lag) Days	Weighted Amount
		[A]	[B]	[C]
	Calculation of NC Retail Amount:			
1	Total Revenue Lag	$ (3,657,503)	42.13	$ (154,105,865)
2				
3	Operation & Maintenance Expense	$ 2,091,224	33.30	$ 69,630,312
4	Depreciation and Amortization	669,787	0.00	-
5	Taxes Other Than Income Taxes	102,197	132.70	13,561,920
6	Interest on Customer Deposits	7,971	137.50	1,096,011
7	Net Income Taxes	112,986	-20.60	(2,327,337)
8	ITC	(2,134)	0.00	-
9	Income for Return	675,472	27.48	18,562,554
10	Total Requirements (Sum L3:L9)	$ 3,657,503	27.48	$ 100,523,460
11				
12	Revenue Lag Days (L1)		42.13	
13	Requirements Lead Days (-L10)		-27.48	
14	Net Lag Days (L12 + L13)		14.65	
15	Daily Requirements (Line 9, Col. A divided by 365)			$ 10,020.56
16				
17	Estimated Cash Working Capital Requirements (L14 x L15)			$ 146,801
18	Add: Cash Working Capital Related to NC Sales Tax			4,760
19	Total Cash Working Capital Requirements (L17 + L18)			$ 151,561
20				
21	**Calculation of Total Company and Jurisdictional Amounts:**			
22	NC Retail Factor			67.0949% [1]
23				
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 225,890
25				

[1] NC Retail Allocation Factor - Net Book Plant

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjustment to Cash Working Capital - Input Worksheet
For the test period ended December 31, 2018

NC-2304
Second Supplemental_S

Line No	Description	Rate		Ratio		Weighted	
1	Debt	4.11%	[1]	48.00%	[1]	1.9716%	[2]
2	Equity	9.75%	[1]	52.00%	[1]	5.0700%	[3]
3	Total ROR (L1 + L2)					7.0416%	
4							
5	Statutory tax rate	23.1693%	[4]				
6	Statutory regulatory fee percentage rate	0.1297%	[5]				
7	Uncollectibles rate	0.24%	[6]				

Notes:
[1] Smith Exhibit 1, Page 2
[2] Debt Rate x Debt Ratio
[3] ROE x Equity Ratio
[4] NC-0104 - 2019 Tax Rate, Line 10
[5] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate, Docket No. M-100, Sub 142
[6] NC-0105 - Development of Uncollectibles Rate

I/A

Supplemental E-1 Item 14

NC-2305
Second Supplemental_S

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	1	**OPERATING REVENUES:**						
	2							
	3							
Calc	4	Service Lag				15.21	A	
	5	Billing Lag						
1	6	Total Retail Sales & Billing Lag		(4,156,399,663)	(3,563,165,280)	1.66	A	
	7	Revenue - REPS		(24,719,022)	(24,719,022)			
	8	Unbilled Revenue	0440.99, 0442.19, 0442.29, 0444.99, 0445.09	13,507,473	12,096,317			
	9							
2	10	Collection Lag				25.01	A	
	11							
	12	Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17)		(4,167,611,212)	(3,575,787,985)	41.88		(149,748,041,162)
	13							
3	14	Total Revenue Lag Sales for Resale		(1,511,358,381)	(134,915,331)	33.73	A	(4,550,694,117)
	15	Provisions For Rate Refunds	0449	118,958,671	104,545,765	41.88	B	4,378,202,395
	16	Total Sales of Electricity (L12 through L14)		(5,560,010,922)	(3,606,157,551)	41.57		(149,920,532,884)
	17							
	18	Other Revenues:						
	19	Forfeited Discounts	0450100, 0450200	(8,582,371)	(7,663,772)	72.30	A	(554,090,707)
4c	20	Miscellaneous Revenues	0451100	(6,165,627)	(5,505,700)	76.00		(418,433,189)
4d	21	RENT - (454) - DIST PLT REL		(5,124,157)	(4,465,630)	41.63		(185,904,174)
4d	22	RENT - (454) - DIST POLE RENTAL REV		(12,960,572)	(10,901,069)	182.00		(1,983,994,633)
4d	23	RENT - (454) - TRANS PLT REL		(639,579)	(381,636)	41.63		(15,887,522)
4d	24	RENT - (454) - ADD FAC - WHLS		(2,806,145)	0	0.00		-
4d	25	RENT - (454) - ADD FAC - RET X LIGHTING		(5,162,072)	(4,617,085)	41.63		(192,209,244)
4d	26	RENT - (454) - ADD FAC - LIGHTING		(4,184,534)	(3,848,777)	41.63		(160,224,580)
4d	27	RENT - (454) - OTHER		(5,086,652)	(3,412,883)	68.21		(232,798,642)
	28	OTHER ELEC REV (456) - PROD PLT REL		(1,924,556)	(1,184,137)	41.88		(49,589,686)
	29	OTHER ELEC REV (456) - TRANS REL		(10,403,096)	(6,207,517)	41.88		(259,960,449)
	30	OTHER ELEC REV (456) - GEN PLT REL		0	0	41.88		-
	31	OTHER ELEC REV (456) - WH D/A		(55,825,581)	0	41.88		-
	32	OTHER ELEC REV (456) - OTHER		(548,940)	(368,310)	41.88		(15,424,225)
	33	OTHER ELEC REV (456) - REPS		(1,114,245)	(1,114,245)	41.88		(46,662,737)
	34	OTHER ELEC REV (456) - OTHER ENERGY		0	0	41.88		-
	35	OTHER ELEC REV (456) - DIST PLT REL	0456630	(1,611,605)	(1,404,491)	41.88		(58,817,730)
	36	REV - OTHER NC RETAIL SPECIFIC		(270,645)	(270,645)	41.88		(11,334,162)
	37	Total Other Revenues (L19 through L36)		(122,410,378)	(51,345,897)	81.51		(4,185,331,681)
	38							-
	39	**Utility Oper Revenues (L16 + L37)**		(5,682,421,300)	(3,657,503,448)	42.13		(154,105,864,564)
	40	ELECTRIC OPERATING REVENUE		5,682,421,300	3,657,503,448			
	41							

I/A

Supplemental E-1 Item 14

NC-2305
Second Supplemental_S

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	42	**OPERATION AND MAINTENANCE EXPENSE:**						
	43							
5 + 6	44	**Fuel Used in Electric Generation**						
	45	OM Prod Energy - Fuel		1,410,621,869	863,120,481	28.49	A	24,588,906,214
	46	RECS Consumption Expense		18,521,748	18,521,748	28.49	A	527,654,628
	47	**Fuel Used in Elec Gen (HFM Greenbook I/S)**	F_FUEL_USED_ELEC_GEN	**1,429,143,617**	**881,642,228**	**28.49**		**25,116,560,842**
7	48							
7	49	OM PROD PURCHASES - CAPACITY COST		109,348,837	67,279,932	30.29	A	2,037,909,147
	50	OM PROD PURCHASES - ENERGY COST		597,919,200	365,384,360	30.29	A	11,067,492,256
	51	OM DEFERRED FUEL EXPENSE	0557980	(316,590,958)	(273,901,174)	28.49	C	(7,803,001,349)
	52	**Purchased Power (Acct 555) + Def Fuel (Acct 557)**	0555XXX	**390,677,079**	**158,763,118**	**33.40**		**5,302,400,054**
	53							
	54	**Total Other O&M Excluding Fuel and Purchased Power**						
9	55							
	56	Total Labor Expense		649,874,113	430,294,724	37.07	A	15,951,025,410
8	57							
	58	Pension and Benefits	0926XXX	115,350,507	76,270,687	13.97	A	1,065,501,492
10	59							
	60	Regulatory Commission Expense	0928000	8,592,296	7,037,696	93.25	A	656,265,126
11	61							
	62	Property Insurance	0924XXX	(774,442)	(525,984)	(222.30)	A	116,926,247
15	63							
	64	Injuries & Damages - Workman's Compensation	0925980	290,241	197,125	0.00	A	-
	65							
	66	Uncollectible Accounts	0904000, 0904001	10,008,548	8,937,301	0.00	A	-
	67							
	68	Remaining Other Oper & Maint Expense		763,377,394	528,607,218	40.52	D	21,421,632,363
	69							
	70	Total O&M Excl. Fuel and Purch. Power		1,546,718,656	1,050,818,766	37.32		39,211,350,637
	71							
	72	**Total Operation and Maintenance Expense (L47 + L52 + L70)**		**3,366,539,352**	**2,091,224,112**	**33.30**		**69,630,311,534**
	73							
	74	Total Depreciation & Amortization & Property Loss		1,060,260,424	669,787,484	0.00	A	-
	75							
	76	**Taxes Other Than Income Taxes**						
	77	Payroll Taxes		39,721,091	26,288,326	48.41	A	1,272,617,860
9	78	Property Tax		101,157,752	68,132,745	186.50		12,706,756,958
13	79	FED HEAVY VEHICLE USE TAX		61,024	48,458	0.00		-
	80	ELECTRIC EXCISE TAX - SC		2,222,093	0	0.00		-
	81	PRIVILEGE TAX		16,355,581	12,243,595	(11.97)		(146,555,834)
13	82	MISC TAX - NC		-6,034,064	-4,517,029	60.00	E	(271,021,743)
	83	MISC TAX - SC & OTHER STATES		-165	949	129.46	A	122,893

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018		NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	84	PUC LICENSE TAX - SC		-121,100		0	0.00	A	-
	85	Taxes Other Than Income Taxes		153,362,212		102,197,044	132.70		13,561,920,134
16	86								
	87	Total Interest on Customer Deposits		8,642,928		7,970,989	137.50	A	1,096,011,021
14	88								
14	89	Federal Income Tax		(66,292,963)		(49,091,019)	44.75	A	(2,196,823,118)
	90	State Income Tax		(3,938,471)		(2,916,502)	44.75		(130,513,463)
	91	Income Tax - Deferred		220,852,977		164,993,723	0.00		-
	92	Net Income Taxes		150,621,543		112,986,202	(20.60)		(2,327,336,581)
	93								
	94	Investment of Tax Credit Adj Net	04114XX	(3,355,660)		(2,133,914)	0.00	A	-
	95								
	96	**Total Utility Operating Expenses (L72 + L74 + L85 + L87 + L92 + L94)**		4,736,070,798		2,982,031,917	27.48		81,960,906,108
	97								
	98	Interest Expense for Electric Operations		315,465,770		211,661,368	87.70	F	18,562,553,881
	99	Income for Equity Return (L100 - L198)		630,884,732		463,810,163	0.00	A	-
	100	Net Operating Income		946,350,502		675,471,531	27.48		18,562,553,881
	101								
	102	**Total Requirements (L96 + L100)**		5,682,421,300		3,657,503,448	27.48		100,523,459,988
	103								
	104								
	105	**Cash Working Capital Related to NC Sales Tax**		4,759,823	G				

	Tickmark Legend
A	Lead/lag days was obtained from Lead/Lag study performed by Ernst & Young. See the Appendix in the Duke Lead Lag Report - DEP file.
B	Revenue refund will be returned through another mechanism; number set to Revenue Lag Days to eliminate effect on Cash Working Capital.
C	Lead/lag days for fuel is being used for this line item to faciliate elimination of this item with the adjustments to cash working capital being proposed in this rate case.
D	Remaining O&M for 2018 includes both nuclear fees and other O&M lines from the 2017 lead/lag study. Lead/lag days reflected is the weighted average of the amounts for those line items from the 2017 study.
E	This expense category is a new breakout for 2018. Lead/lag days was determined based on review of activity for 2018. A majority of the balance is related to a refund which was accrued in March and received in May. As such, a 60 day lag seems reasonable.
F	See 2017 Interest Lead Days tab for calculation.
G	Cash Working Capital Related to NC Sales Tax for 2018 was calculated on Schedule 17.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

SMITH
Exhibit No. 4
Second Supplemental_S

Line	Description	Note	Federal EDIT - Unprotected, PP&E related NC Retail (A)	Federal EDIT - Unprotected, non PP&E related NC Retail (B)	NC EDIT NC Retail (C)	Deferred Revenue NC Retail (D)	Total NC Retail (E)
1	Regulatory Federal EDIT liabilIty including gross up on the books as of 12/31/2018, based on 2017 tax returns	[1]	$ (326,704)	$ 4,862	$ (23,726)		(345,568)
2	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2018-12/31/2018	[1]		$ (30,548)	$ -		(30,548)
3	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2019-8/31/2020	[1]		$ (50,913)	$ -		(50,913)
4	Regulatory Federal EDIT liability including gross up and transition of Protected to Unprotected Regulatory liability as of 8/31/2020 (Sum of L1 to L3)	[1]	$ (326,704)	$ (76,598)	$ (23,726)	$ -	(427,028)
5	Adjustment to implement ASU 2018-02	[1]		$ (34)	$ -		(34)
6	Adjustment for Amended 2017 Federal Return	[1]	$ (415)				(415)
7	Deferred revenues related to 2017 Federal Tax Rate Change as of 12/31/2018	[1]				$ (108,392)	(108,392)
8	Other projected updates through 2/29/2020	[2]			$ (271)	$ (1,923)	(2,194)
9	Regulatory liabilIty for federal tax change including gross up for NC Retail, for Year 1 rider calculation (Sum of L4 to L8)		$ (327,119)	$ (76,631)	$ (23,998)	$ (110,315)	(538,063)
10	Years of rider amortization		20	20	5	2	
11	Annual amortization amount (L9 / L10)		$ (16,356)	$ (3,832)	$ (4,800)	$ (55,157)	(80,144)

[1] Excess deferred tax liability (EDIT) as of 12/31/2018 by jurisdiction, and forecast transition to new rates effective date between categories based on Tax analysis of ADIT.
Federal EDIT related to the federal tax changes booked to the 0254036 and 0254038 accounts is included in other Working Capital in the per books cost of service.
NC EDIT related to the NC state tax reduction deferred to the 0254150 account not included for recovery in NC EDIT rider approved in prior DEP NC rate case.
This NC EDIT is included in other Working Capital in the per books cost of service.
Revenues deferred for federal tax changes with accrued returns in the 0229010 account, are currently excluded from rate base in the per books COSS.

[2] Projected updates to the Federal and NC tax EDIT during 2019 by Tax
NORTH CAROLINA RETAIL, Page 3, Line 1 return accruals on deferred revenues in the 0229010 account projected through 2/29/2020.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Smith Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	48.00%	4.11%	1.51%
Equity	52.00%	9.75%	5.07%
			6.58%
Statutory Tax Rate			23.17%
Retention factor for NCUC Fee, Uncollectibles			99.63%

Annual Rider Calculation

Year		Beginning Balance, Page 1, L9	Amortization - From Page 1, L: Federal EDIT - Unprotected, PP&E related	Federal EDIT - Unprotected, non PP&E related	NC EDIT	Deferred Revenue	Total Amortization	Ending Balance before Return	Average of Beginning and Ending Balance	EDIT Balance in Base Rates, Page 1, L1	Change in Regulatory Liability for Rider Return	Return for Rider	Rider Revenues	Rider Revenues NCUC Fee, Uncollectibles	
		(A)	(B)	(C)	(D)	(E)	(F) =(B)+(C)+(D)+[E]	(G) = (A) - (F)	(H) = ((A) + (G)) /2	(I)	(J) = (H) - (I)	(K) = (J) x After Tax WACC	(L) = (F) + (K)	(M) = (L) / Retention Factor	
Sep 20- Nov 21	1	(538,063)	(16,356)	(3,832)	(4,800)	(55,157)	(80,144)	(457,918)	($497,991)	(427,028)	($70,962)	($4,673)	(84,817)	(85,131)	
Dec 21- Nov 22	2	(457,918)	(16,356)	(3,832)	(4,800)	(55,157)	(80,144)	(377,774)	($417,846)	(427,028)	$9,182	$605	(79,540)	(79,834)	[1]
Dec 22- Nov 23	3	(377,774)	(16,356)	(3,832)	(4,800)	-	(24,987)	(352,787)	($365,280)	(427,028)	$61,748	$4,066	(20,921)	(20,999)	[1]
Dec 23- Nov 24	4	(352,787)	(16,356)	(3,832)	(4,800)	-	(24,987)	(327,800)	($340,293)	(427,028)	$86,735	$5,711	(19,276)	(19,347)	[1]
Dec 24- Nov 25	5	(327,800)	(16,356)	(3,832)	(4,800)	-	(24,987)	(302,813)	($315,306)	(427,028)	$111,722	$7,357	(17,630)	(17,696)	[1]

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by September 30th for Commission approv

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL

	Deferred Revenue for Federal Tax Rate Change in account 0229010	NC Retail
1	Projected Changes in Deferred Revenue for Federal Tax Rate Change through Feb 2020	($1,923,073)

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (a) (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (304,779)	$ 3,352,725	$ 438,211	$ 3,790,936
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(34,636)	847,006		847,006
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(187,341)	863,478	1,618	865,096
5	Depreciation and amortization	1,060,260	669,787	247,926	917,713		917,713
6	General taxes	153,362	102,197	2,381	104,578		104,578
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	EDIT Amortization	-	-	(30,548)	(30,548)	-	(30,548)
9	Net income taxes	150,622	112,986	(49,917)	63,069	100,907	163,976
10	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
11	Total electric operating expenses	4,736,071	2,982,032	(55,580)	2,926,452	102,525	3,028,976
12	Operating income	$ 946,351	$ 675,472	$ (249,198)	$ 426,273	$ 335,686	$ 761,960
13	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 396,705 (d)	$ 10,255,755	$ 55,637 (f)	$ 10,311,392
14	Rate of return on North Carolina retail rate base		6.85%		4.16%		7.39%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

I/A

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

					North Carolina Retail Operations					
					Before Proposed Increase			After Proposed Increase		
Line No.	Description		Dec. 31, 2018 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt		$ 8,108,191	47.00%	$ 4,820,205	4.11%	$ 197,987	$ 4,846,354	4.11%	$ 199,061
2	Members' equity	(a)	8,717,931	53.00%	5,435,550	4.20%	228,287	5,465,038	10.30%	562,899
3	Total		$ 16,826,122	100.00%	$ 10,255,755 (b)		$ 426,273 (c)	$ 10,311,392 (b)		761,960
4	Operating income before increase (Line 3, Column 5)									426,273
5	Additional operating income required (Line 3 minus Line 4)									335,686
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue									(249)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)									102,774
8	Additional revenue requirement									$ 438,211
9	Revenue Adjustments	(d)								$ (91,232)
10	Net Increase									$ 346,979

-- Some totals may not foot or compute due to rounding.

Notes: (a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	-	(52,114)	-	(172,813)
1(D)		Annualize retail revenues for current rates- Supplemental	24,093	-	-	89	-	-	-	5,562	-	18,443
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	-	3,304	-	10,955
2(F)		Update fuel costs to proposed rate- Rebuttal	-	24,010	-	-	1,684	-	-	(5,953)	-	(19,741)
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	-	(13,653)	-	(45,273)
11(E)		Normalize for weather- Supplemental	4,882	(2,252)	-	18	-	-	-	1,649	-	5,467
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	-	534	-	1,771
4(I)		Annualize revenues for customer growth- Second Supplemental	(15,625)	(9,976)	-	(58)	-	-	-	(1,296)	-	(4,296)
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	-	63,161	-	128,547
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	(31)	-	-	-	7	-	24
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	-	556	-	1,843
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	(161)	-	-	-	37	-	124
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	-	(9,747)	(1,481)	(30,841)
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	(661)	-	-	153	-	508
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	-	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	-	(17,857)	-	(59,213)
10(I)		Adjust for post test year additions to plant in service- Second Supplemental	-	-	-	-	(2,200)	(850)	-	707	-	2,344
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	-	(24,553)	-	(81,419)
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	-	(9,949)	-	-	2,305	-	7,644
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	-	(304)	-	(1,007)
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	1,034	-	-	-	(240)	-	(794)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	-	4,542	-	15,060
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	(722)	-	181	-	126	-	416
14		Update benefits costs	-	-	-	(3,060)	-	-	-	709	-	2,351
14(D)		Update benefits costs- Supplemental	-	-	-	(3,298)	-	-	-	764	-	2,534
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	-	1,444	-	4,788
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	42	-	-	-	(10)	-	(32)
16	*	Amortize rate case costs	-	-	-	701	-	-	-	(162)	-	(539)
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	-	341	-	1,129
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	(205)	-	-	-	47	-	157

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
18	Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	-	434	-	1,438
19	* Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	-	988	-	3,276
19(I)	Adjust for Merger Related Costs	-	-	-	-	(12)	-	-	3	-	10
20	* Amortize Severance Costs	-	-	-	(23,366)	-	-	-	5,414	-	17,952
20(G)	Amortize Severance Costs- Partial Settlement	-	-	-	(774)	-	-	-	179	-	594
21	Adjust NC income taxes for rate change	-	-	-	-	-	-	-	(2,183)	-	2,183
22	* Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	123	-	(123)
22(I)	Synchronize interest expense with end of period rate base- Second Supplemental	-	-	-	-	-	-	-	2,959	-	(2,959)
23	* Adjust cash working capital	-	-	-	-	-	-	-	122	-	(122)
23(I)	Adjust cash working capital- Second Supplemental	-	-	-	-	-	-	-	(35)	-	35
24	Adjust coal inventory	-	-	-	-	-	-	-	-	-	-
24(C)	Adjust coal inventory- Supplemental	-	-	-	-	-	-	-	-	-	-
25	* Adjust for credit card fees	-	-	-	5,197	-	-	-	(1,204)	-	(3,993)
25(F)	Adjust for credit card fees- Rebuttal	-	-	-	72	-	-	-	(17)	-	(55)
26	Adjust Depreciation for new rates	-	-	-	-	89,601	-	-	(20,760)	-	(68,841)
26(D)	Adjust Depreciation for new rates- Supplemental	-	-	-	-	(873)	-	-	202	-	671
27	Adjust vegetation management expenses	-	-	-	5,757	-	-	-	(1,334)	-	(4,424)
28	Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	-	21	-	70
28(G)	Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	(1,826)	-	-	423	-	1,403
29	* Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	-	(10,129)	-	(33,588)
29(I)	Update deferred balance and amortize storm costs- Second Supplemental	-	-	-	-	(45,362)	-	-	10,510	-	34,852
30	Adjust other revenue	(4,155)	-	-	(5)	-	-	-	(962)	-	(3,188)
31	Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	-	54	-	180
32	* Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	-	1,767	-	5,859
32(F)	Reflect retirement of Asheville Steam Generating Plant- Rebuttal	-	-	-	-	10,381	1,032	-	(2,644)	-	(8,769)
33	Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	-	(1,144)	-	(3,794)
33(A)	Adjust for CertainTeed payment obligation- Supplemental	-	-	-	(4,939)	-	-	-	1,144	-	3,794
34	* Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	-	(4,565)	-	(15,138)
34(G)	Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	-	(7,568)	(4,624)	-	-	2,825	-	9,367

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT 0.0000% (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	-	455	-	1,510
36(E)	Correct Lead Lag- Supplemental	-	-	-	-	-	-	-	-	-	-
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	-	-	-	(30,548)	7,078	-	23,470
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	(2,834)	-	-	-	657	-	2,177
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	9,300	-	-	-	(2,155)	-	(7,145)
40	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ -	$ (74,904)	$ (1,481)	$ (319,441)
40(I)	Change from Application	13,351	11,782	-	(10,035)	(53,443)	363	(30,548)	24,987	-	70,243
41	Total adjustments	$ (304,779)	$ (34,636)	$ (1,965)	$ (187,341)	$ 247,926	$ 2,381	$ (30,548)	$ (49,917)	$ (1,481)	$ (249,198)

-- Some totals may not foot or compute due to rounding.
Notes: * Identification required by NCUC Rule R1-17(b)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	225,760	-	225,760
1(D)		Annualize retail revenues for current rates- Supplemental	-	-	-	-	-	-	-	-	(24,093)	-	(24,093)
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,311)	-	(14,311)
2(F)		Update fuel costs to proposed rate- Rebuttal	-	-	-	-	-	-	-	-	25,789	-	25,789
3	*	Normalize for weather	-	-	-	-	-	-	-	-	59,144	-	59,144
11(E)		Normalize for weather- Supplemental	-	-	-	-	-	-	-	-	(7,142)	-	(7,142)
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,314)	-	(2,314)
4(I)		Annualize revenues for customer growth- Second Supplemental	-	-	-	-	-	-	-	-	5,613	-	5,613
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,869)	-	(11,869)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,932)	(94,010)	(261,943)
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	-	-	-	-	-	(31)	230	199
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,408)	-	(2,408)
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	-	-	-	-	-	(162)	-	(162)
8		Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,290	-	40,290
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	-	-	-	-	(663)	-	(663)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,079	-	4,079
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,355	120,182	197,537
10(I)		Adjust for post test year additions to plant in service- Second Supplemental	(187,320)	195,347	-	20,220	(25,761)	-	-	2,486	(3,062)	(69)	(3,131)
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	106,364	29,499	135,863
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,986)	(2,835)	(12,820)
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,316	-	1,316
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	1,038	-	1,038
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,674)	-	(19,674)
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	(544)	-	(544)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,071)	-	(3,071)
14(D)		Update benefits costs- Supplemental	-	-	-	-	-	-	-	-	(3,310)	-	(3,310)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,255)	-	(6,255)
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	-	-	-	-	-	42	-	42
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	704	186	889
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	(2,670)	619	-	-	(2,051)	-	(186)	(186)
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,475)	-	(1,475)
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	-	-	-	-	-	(206)	-	(206)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
18	Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,878)	(5,821)	(7,699)
19	* Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,280)	31	(4,248)
19(I)	Adjust for Merger Related Costs	(558)	55	-	-	-	-	-	(504)	(12)	(46)	(58)
20	* Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,453)	1,621	(21,832)
20(G)	Amortize Severance Costs- Partial Settlement	-	-	-	(23,297)	5,398	-	-	(17,899)	(777)	(1,621)	(2,398)
21	Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,851)	-	(2,851)
22	* Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22(I)	Synchronize interest expense with end of period rate base- Second Supplemental	-	-	-	-	-	-	-	-	3,865	-	3,865
23	* Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	160	(2,447)	(2,287)
23(I)	Adjust cash working capital- Second Supplemental	-	-	-	7,582	-	-	-	7,582	(46)	691	645
24	Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24(C)	Adjust coal inventory- Supplemental	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,922)	(1,922)
25	* Adjust for credit card fees	-	-	-	-	-	-	-	-	5,217	-	5,217
25(F)	Adjust for credit card fees- Rebuttal	-	-	-	-	-	-	-	-	72	-	72
26	Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,933	(8,037)	81,896
26(D)	Adjust Depreciation for new rates- Supplemental	-	-	-	-	-	-	-	-	(876)	20	(857)
27	Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,779	-	5,779
28	Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
28(G)	Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	-	-	-	-	(1,833)	-	(1,833)
29	* Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,879	42,594	86,473
29(I)	Update deferred balance and amortize storm costs- Second Supplemental	(68,639)	2,231	-	(612,045)	141,807	-	-	(536,647)	(45,530)	(48,594)	(94,125)
30	Adjust other revenue	-	-	-	-	-	-	-	-	4,165	-	4,165
31	Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(235)	-	(235)
32	* Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,654)	(2,965)	(10,619)
32(F)	Reflect retirement of Asheville Steam Generating Plant- Rebuttal	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,456	6,809	18,265
33	Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,957	-	4,957
33(A)	Adjust for CertainTeed payment obligation- Supplemental	-	-	-	-	-	-	-	-	(4,957)	-	(4,957)
34	* Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,776	2,230	22,006
34(G)	Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	(248)	(27,188)	6,299	-	-	(21,136)	(12,237)	(1,915)	(14,152)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,972)	-	(1,972)
36(E)	Correct Lead Lag- Supplemental	-	-	-	(8,580)	-	-	-	(8,580)	-	(775)	(775)
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	30,548	(7,078)	-	-	23,470	(30,661)	2,121	(28,540)
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	-	-	-	-	-	(2,844)	-	(2,844)
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	-	-	-	-	-	9,334	-	9,334
40	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 417,313	$ 83,718	$ 501,031
40(I)	Change from Application	30,535	(13,039)	(21,565)	(656,564)	130,814	-	-	(529,819)	(91,764)	(47,873)	(139,637)
41	Total adjustments	$ 611,093	$ (115,487)	$ (172,644)	$ 235,143	$ (58,470)	$ -	$ (102,930)	$ 396,705	$ 325,549	$ 35,845	$ 361,394

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

Smith
Exhibit 1
Page 3
(continued)

I/A

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(115,487)	(8,157,546)
3	Net electric plant		16,126,825	10,763,851	495,606	11,259,457
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	235,143	(140,029)
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(58,470)	(1,391,098)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 396,705	$ 10,255,755

-- Some totals may not foot or compute due to rounding.

I/A

Smith Exhibit 1
Second Supplemental

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (179,365)	$ 9,877,155
2	Transmission Plant	2,746,389	1,643,263	264,402	1,907,665
3	Distribution Plant	6,944,764	6,052,263	433,108	6,485,371
4	General Plant	628,616	465,435	68,399	533,833
5	Intangible Plant	527,370	358,178	51,912	410,090
6	Subtotal	27,398,830	18,575,658	638,456	19,214,114
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (50,423)	$ (4,441,180)
2	Transmission Reserve	(816,198)	(488,611)	(27,693)	(516,304)
3	Distribution Reserve	(3,235,148)	(2,819,386)	26,382	(2,793,003)
4	General Reserve	(167,536)	(124,045)	(30,822)	(154,867)
5	Intangible Reserve	(322,831)	(219,260)	(32,932)	(252,192)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (115,487)	$ (8,157,546)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

No.	Description	Rate
8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations: Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(28,011)	(b)	132,130	55,637	(c)	187,768
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		263,154		(174,137)	-		(174,137)
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		235,143		(23,441)	55,637		32,197
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 235,143		$ (140,029)	$ 55,637		$ (84,391)

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

I/A

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental
Corrected

Smith Exhibit 1 Supplemental Rebuttal

Line No.	Description	Ref #	SUMMARY OF PROPOSED REVENUE ADJUSTMENTS: Application	Partial Settlement	Second Supplemental	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(96,523)	(96,523)	(96,523)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(173,156)	(147,750)	(147,750)
6	Net Revenue Increase		$ 463,619	$ 321,573	$ 346,979	$ 346,979
7						

Line No.	Description	Ref #	CHANGE IN OP INCOME: Application	Partial Settlement	Second Supplemental	Total Adjs [1]	CHANGE IN RATE BASE: Application	Partial Settlement	Second Supplemental	Total Change [2]
8										
9										
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ -	$ (154,370)	$ -	$ -	$ -	$ -
11	Update fuel costs to proposed rate	NC-0200	10,955	-	-	(8,786)	-	-	-	-
12	Normalize for weather	NC-0300	(45,273)	-	-	(39,806)	-	-	-	-
13	Annualize revenues for customer growth	NC-0400	1,771	-	(2,771)	(2,525)	-	-	-	-
14	Eliminate unbilled revenues	NC-0500	9,086	-	-	9,086	-	-	-	-
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	-	128,571	(1,037,885)	-	-	(1,037,885)
16	Adjust O&M for executive compensation	NC-0700	1,843	124	-	1,967	-	-	-	-
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	-	(30,333)	-	-	-	-
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	-	(3,122)	-	-	-	-
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	(9)	(4,732)	(56,870)	1,326,826	(1,507)	139,224	1,329,312
20	Amortize deferred environmental costs	NC-1100	(81,419)	-	-	(73,775)	325,675	-	-	295,100
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	37	1,420	(1,802)	-	-	-	-
22	Normalize O&M labor expenses	NC-1300	15,060	3,009	(3,633)	15,476	-	-	-	-
23	Update benefits costs	NC-1400	2,351	-	-	4,885	-	-	-	-
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	-	4,756	-	-	-	-
25	Amortize rate case costs	NC-1600	(539)	-	-	(539)	2,051	(2,051)	-	-
26	Adjust aviation expenses	NC-1700	1,129	157	-	1,287	-	-	-	-
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	-	1,438	(64,423)	-	-	(64,423)
28	Adjust for Merger Related Costs	NC-1900	3,276	-	2	3,285	347	-	(53)	(157)
29	Amortize Severance Costs	NC-2000	17,952	-	-	18,547	17,899	(16,717)	-	-
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	-	2,183	-	-	-	-
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(2,433)	623	(3,081)	-	-	-	-
32	Adjust cash working capital	NC-2300	(122)	17	(9)	(87)	(27,013)	3,904	(2,116)	(19,431)
33	Adjust coal inventory	NC-2400	-	-	-	-	9,641	-	-	(11,603)
34	Adjust for credit card fees	NC-2500	(3,993)	-	-	(4,048)	-	-	-	-
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	-	(68,170)	(88,728)	-	-	(88,728)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	-	(4,424)	-	-	-	-
37	Adjust reserve for end of life nuclear costs	NC-2800	70	1,403	-	1,473	-	-	-	-
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	34,448	7	1,264	470,238	(531,121)	27	(66,408)
39	Adjust other revenue	NC-3000	(3,188)	-	-	(3,188)	-	-	-	-
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	-	180	-	-	-	-
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	-	-	(2,910)	(32,730)	-	-	42,550
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-	-	-	-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	4,299	-	(5,771)	24,624	(16,124)	-	3,488
44	Adjust Purchased Power	NC-3500	1,510	-	-	1,510	-	-	-	-
45	Correct Lead Lag	NC-3600	-	-	-	-	-	-	-	(8,580)
46	Amortize Prot EDIT	NC-3700	-	23,470	-	23,470	-	23,470	-	23,470
47	Remove certain Settlement Items	NC-3800	-	2,177	-	2,177	-	-	-	-
48	Normalize for storm costs	NC-3900	-	(7,145)	-	(7,145)	-	-	-	-
49										
50		Adjustments	$ (319,441)	$ 59,554	$ (9,094)	$ (249,198)	$ 926,524	$ (540,146)	$ 137,082	$ 396,705
51										

Line No.	Description		Application	Partial Settlement	Second Supplemental	Total	Description		Application	Partial Settlement	Second Supplemental	Total
52	Operating income	[3]	675,472	675,472	675,472	675,472	Rate base	[4]	9,859,050	9,859,050	9,859,050	9,859,050
53	Total Adjustments		(319,441)	(240,104)	(249,198)	(249,198)	Total Adjustments		926,524	259,622	396,705	396,705
54	Adjusted Net Operating Income		356,031	435,367	426,273	426,273	Adjusted Rate Base		10,785,574	10,118,673	10,255,755	10,255,755
55												
56	Revenue Requirement Impact		417,313	(77,801)	11,880	325,549			83,718	(48,806)	12,386	35,845
			417,313	313,669	325,549	325,549			83,718	23,459	35,845	35,845

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

I/A

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 2
Second Supplemental
Corrected

Line No.	Description	NC RETAIL	Reference
1	Additional base revenue requirement	$ 438,211	Smith Second Supplemental Exhibit 1
2	REVISED Annual EDIT Rider 1	7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback	(96,523)	Smith Partial Settlement Exhibit 4
4	Regulatory Asset and Liability Rider	(2,091)	Smith Exhibit 5
5	Subtotal	(91,232)	Sum L3 - L17
6	Net Revenue Increase	$ 346,979	

I/A

Smith Exhibit 3
Second Supplemental

DUKE ENERGY PROGRESS, LLC
Reconciliation of Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Item	Amount
1	Revenue requirement increase per Company application		**585,961**
2	Revenue impact of Company supplemental adjustments		(51,617)
3	Revenue impact of Company rebuttal adjustments		9,918
4	Revenue impact of Settlement adjustments		(131,457)
5	Revenue requirement increase per Company Partial Settlement Filing		**$ 412,805**
6			
7	Updated Proformas:		
8	NC0400	Annualize revenues for customer growth	3,620
9	NC1000	Adjust for post test year additions to plant in service	18,762
10	NC1200	Annualize O&M non-labor expenses	(1,855)
11	NC1300	Normalize O&M labor expenses	4,746
12	NC1900	Adjust merger related costs	(7)
13	NC2200	Adjust synchronized interest expense	(813)
14	NC2300	Adjust cash working capital under present rates	(179)
15	NC2300	Adjust cash working capital under proposed rates	1,141
16	NC2900	Update deferred balance and amortize storm costs	(7)
17	Rounding		(1)
18	Total Revenue impact of adjustments		$ 25,406
19			
20	Revenue Requirement per Smith Exhibit 1 Second Supplemental		**$ 438,211**

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (a) (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (304,779)	$ 3,352,725	$ 389,438	$ 3,742,162
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(34,636)	847,006		847,006
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(187,341)	863,478	1,438	864,916
5	Depreciation and amortization	1,060,260	669,787	247,926	917,713		917,713
6	General taxes	153,362	102,197	2,381	104,578		104,578
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	EDIT Amortization	-	-	(30,548)	(30,548)	-	(30,548)
9	Net income taxes	150,622	112,986	(50,888)	62,098	89,671	151,769
10	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
11	Total electric operating expenses	4,736,071	2,982,032	(56,552)	2,925,480	91,109	3,016,589
12	Operating income	$ 946,351	$ 675,472	$ (248,227)	$ 427,244	$ 298,329	$ 725,573
13	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 395,635 (d)	$ 10,254,686	$ 49,457 (f)	$ 10,304,142
14	Rate of return on North Carolina retail rate base		6.85%		4.17%		7.04%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

I/A

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

				North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
Line No.	Description	Dec. 31, 2018 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	$ 8,108,191	48.00%	$ 4,922,249	4.11%	$ 202,178	$ 4,945,988	4.11%	$ 203,153
2	Members' equity (a)	8,717,931	52.00%	5,332,437	4.22%	225,066	5,358,154	9.75%	522,420
3	Total	$ 16,826,122	100.00%	$ 10,254,686 (b)		$ 427,244 (c)	$ 10,304,142 (b)		725,573
4	Operating income before increase (Line 3, Column 5)								427,244
5	Additional operating income required (Line 3 minus Line 4)								298,329
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								(226)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)								91,335
8	Additional revenue requirement								$ 389,438
9	Revenue Adjustments (d)								$ (90,998)
10	Net Increase								$ 298,439

-- Some totals may not foot or compute due to rounding.

Notes:
(a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	-	(52,114)	-	(172,813)
1(D)		Annualize retail revenues for current rates- Supplemental	24,093	-	-	89	-	-	-	5,562	-	18,443
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	-	3,304	-	10,955
2(F)		Update fuel costs to proposed rate- Rebuttal	-	24,010	-	-	1,684	-	-	(5,953)	-	(19,741)
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	-	(13,653)	-	(45,273)
11(E)		Normalize for weather- Supplemental	4,882	(2,252)	-	18	-	-	-	1,649	-	5,467
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	-	534	-	1,771
4(I)		Annualize revenues for customer growth- Second Supplemental	(15,625)	(9,976)	-	(58)	-	-	-	(1,296)	-	(4,296)
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	-	63,161	-	128,547
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	(31)	-	-	-	7	-	24
7		Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	-	556	-	1,843
7(G)		Adjust O&M for executive compensation- Partial Settlement	-	-	-	(161)	-	-	-	37	-	124
8		Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	-	(9,747)	(1,481)	(30,841)
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	(661)	-	-	153	-	508
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	-	(942)	-	(3,122)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	-	(17,857)	-	(59,213)
10(I)		Adjust for post test year additions to plant in service- Second Supplemental	-	-	-	-	(2,200)	(850)	-	707	-	2,344
11	*	Amortize deferred environmental costs	-	-	-	-	105,972	-	-	(24,553)	-	(81,419)
11(E)		Amortize deferred environmental costs- Supplemental	-	-	-	-	(9,949)	-	-	2,305	-	7,644
12		Annualize O&M non-labor expenses	-	-	-	1,311	-	-	-	(304)	-	(1,007)
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	1,034	-	-	-	(240)	-	(794)
13	*	Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	-	4,542	-	15,060
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	(722)	-	181	-	126	-	416
14		Update benefits costs	-	-	-	(3,060)	-	-	-	709	-	2,351
14(D)		Update benefits costs- Supplemental	-	-	-	(3,298)	-	-	-	764	-	2,534
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	-	1,444	-	4,788
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	42	-	-	-	(10)	-	(32)
16	*	Amortize rate case costs	-	-	-	701	-	-	-	(162)	-	(539)
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	-	-	-	-	-	-	-
17		Adjust aviation expenses	-	-	-	(1,452)	-	(18)	-	341	-	1,129
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	(205)	-	-	-	47	-	157

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	-	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	-	988	-	3,276
19(I)		Adjust for Merger Related Costs	-	-	-	-	(12)	-	-	3	-	10
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	-	5,414	-	17,952
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(774)	-	-	-	179	-	594
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	(2,183)	-	2,183
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	123	-	(123)
22(I)		Synchronize interest expense with end of period rate base- Updated Settlement_S	-	-	-	-	-	-	-	1,981	-	(1,981)
23	*	Adjust cash working capital	-	-	-	-	-	-	-	122	-	(122)
23(I)		Adjust cash working capital- Updated Settlement_S	-	-	-	-	-	-	-	(29)	-	29
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-	-
24(C)		Adjust coal inventory- Supplemental	-	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	-	(1,204)	-	(3,993)
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	72	-	-	-	(17)	-	(55)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	-	(20,760)	-	(68,841)
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	(873)	-	-	202	-	671
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	-	21	-	70
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	(1,826)	-	-	423	-	1,403
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	-	(10,129)	-	(33,588)
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	-	-	-	-	(45,362)	-	-	10,510	-	34,852
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	-	1,767	-	5,859
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	-	-	-	-	10,381	1,032	-	(2,644)	-	(8,769)
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	-	(1,144)	-	(3,794)
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	(4,939)	-	-	-	1,144	-	3,794
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	-	(4,565)	-	(15,138)
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	-	(7,568)	(4,624)	-	-	2,825	-	9,367

Smith Exhibit 1
Page 3
(continued)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Electric Operating Revenue	Fuel Used in Electric Generation	Purchased Power and Net Interchange	Wages Benefits Materials Etc.	Depreciation and Amortization	General Taxes	EDIT 0.0000%	Income Taxes 23.1693%	Amortization of ITC	Operating Income
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	-	455	-	1,510
36(E)	Correct Lead Lag- Supplemental	-	-	-	-	-	-	-	-	-	-
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	-	-	-	(30,548)	7,078	-	23,470
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	(2,834)	-	-	-	657	-	2,177
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	9,300	-	-	-	(2,155)	-	(7,145)
40	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ -	$ (74,904)	$ (1,481)	$ (319,441)
40(I)	Change from Application	13,351	11,782	-	(10,035)	(53,443)	363	(30,548)	24,016	-	71,214
41	Total adjustments	$ (304,779)	$ (34,636)	$ (1,965)	$ (187,341)	$ 247,926	$ 2,381	$ (30,548)	$ (50,888)	$ (1,481)	$ (248,227)

-- Some totals may not foot or compute due to rounding.
Notes: * Identification required by NCUC Rule R1-17(b)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1	Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	225,760	-	225,760
1(D)	Annualize retail revenues for current rates- Supplemental	-	-	-	-	-	-	-	-	(24,093)	-	(24,093)
2	Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,311)	-	(14,311)
2(F)	Update fuel costs to proposed rate- Rebuttal	-	-	-	-	-	-	-	-	25,789	-	25,789
3	* Normalize for weather	-	-	-	-	-	-	-	-	59,144	-	59,144
11(E)	Normalize for weather- Supplemental	-	-	-	-	-	-	-	-	(7,142)	-	(7,142)
4	* Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,314)	-	(2,314)
4(I)	Annualize revenues for customer growth- Second Supplemental	-	-	-	-	-	-	-	-	5,613	-	5,613
5	Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,869)	-	(11,869)
6	Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,932)	(94,010)	(261,943)
6(C)	Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	-	-	-	-	-	(31)	5,058	5,027
7	Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,408)	-	(2,408)
7(G)	Adjust O&M for executive compensation- Partial Settlement	-	-	-	-	-	-	-	-	(162)	-	(162)
8	Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,290	-	40,290
8(D)	Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	-	-	-	-	(663)	-	(663)
9	Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,079	-	4,079
10	* Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,355	120,182	197,537
10(I)	Adjust for post test year additions to plant in service- Second Supplemental	(187,320)	195,347	-	20,220	(25,761)	-	-	2,486	(3,062)	(6,254)	(9,315)
11	* Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	106,364	29,499	135,863
11(E)	Amortize deferred environmental costs- Supplemental	-	-	-	(39,795)	9,220	-	-	(30,575)	(9,986)	(4,208)	(14,193)
12	Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,316	-	1,316
12(I)	Annualize O&M non-labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	1,038	-	1,038
13	* Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,674)	-	(19,674)
13(I)	Normalize O&M labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	(544)	-	(544)
14	Update benefits costs	-	-	-	-	-	-	-	-	(3,071)	-	(3,071)
14(D)	Update benefits costs- Supplemental	-	-	-	-	-	-	-	-	(3,310)	-	(3,310)
15	* Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,255)	-	(6,255)
15(E)	Levelize nuclear refueling outage costs- Supplemental	-	-	-	-	-	-	-	-	42	-	42
16	* Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	704	186	889
16(G)	Amortize rate case costs- Partial Settlement	-	-	-	(2,670)	619	-	-	(2,051)	-	(186)	(186)
17	Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,475)	-	(1,475)
17(G)	Adjust aviation expenses- Partial Settlement	-	-	-	-	-	-	-	-	(206)	-	(206)

Smith Exhibit 1 Page 3 (cond)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,878)	(5,521)	(7,400)
19	*	Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,280)	31	(4,248)
19(I)		Adjust for Merger Related Costs	(558)	55	-	-	-	-	-	(504)	(12)	(45)	(57)
20	*	Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,453)	1,621	(21,832)
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(23,297)	5,398	-	-	(17,899)	(777)	(1,621)	(2,398)
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,851)	-	(2,851)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22(I)		Synchronize interest expense with end of period rate base- Updated Settlement_S	-	-	-	-	-	-	-	-	2,588	-	2,588
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	160	(2,447)	(2,287)
23(I)		Adjust cash working capital- Updated Settlement_S	-	-	-	6,513	-	-	-	6,513	(37)	690	653
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24(C)		Adjust coal inventory- Supplemental	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,868)	(1,868)
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-	5,217	-	5,217
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	-	-	-	-	-	72	-	72
26		Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,933	(8,037)	81,896
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	-	-	-	-	(876)	432	(444)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,779	-	5,779
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	-	-	-	-	(1,833)	-	(1,833)
29	*	Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,879	42,594	86,473
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	(68,639)	2,231	-	(612,045)	141,807	-	-	(536,647)	(45,530)	(48,285)	(93,816)
30		Adjust other revenue	-	-	-	-	-	-	-	-	4,165	-	4,165
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(235)	-	(235)
32	*	Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,654)	(2,965)	(10,619)
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,456	6,611	18,067
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,957	-	4,957
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	-	-	-	-	-	(4,957)	-	(4,957)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,776	2,230	22,006
34(G)		Amortize deferred balance Asheville Combined Cycle- Partial Settlement	-	-	(248)	(27,188)	6,299	-	-	(21,136)	(12,237)	(1,931)	(14,169)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,972)	-	(1,972)
36(E)	Correct Lead Lag- Supplemental	-	-	-	(8,580)	-	-	-	(8,580)	-	(735)	(735)
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	30,548	(7,078)	-	-	23,470	(30,661)	2,011	(28,649)
38(G)	Remove certain Settlement Items- Partial Settlement	-	-	-	-	-	-	-	-	(2,844)	-	(2,844)
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	-	-	-	-	-	9,334	-	9,334
40	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 417,313	$ 79,408	$ 496,720
40(I)	Change from Application	30,535	(13,039)	(21,565)	(657,633)	130,814	-	-	(530,888)	(93,033)	(45,500)	(138,532)
41	Total adjustments	$ 611,093	$ (115,487)	$ (172,644)	$ 234,074	$ (58,470)	$ -	$ (102,930)	$ 395,635	$ 324,280	$ 33,908	$ 358,188

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(115,487)	(8,157,546)
3	Net electric plant		16,126,825	10,763,851	495,606	11,259,457
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	234,074	(141,098)
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	(58,470)	(1,391,098)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 395,635	$ 10,254,686

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (179,365)	$ 9,877,155
2	Transmission Plant	2,746,389	1,643,263	264,402	1,907,665
3	Distribution Plant	6,944,764	6,052,263	433,108	6,485,371
4	General Plant	628,616	465,435	68,399	533,833
5	Intangible Plant	527,370	358,178	51,912	410,090
6	Subtotal	27,398,830	18,575,658	638,456	19,214,114
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

		Total Company	North Carolina Retail Operations		
No.	Description	Per Books (Col. 1)	Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (50,423)	$ (4,441,180)
2	Transmission Reserve	(816,198)	(488,611)	(27,693)	(516,304)
3	Distribution Reserve	(3,235,148)	(2,819,386)	26,382	(2,793,003)
4	General Reserve	(167,536)	(124,045)	(30,822)	(154,867)
5	Intangible Reserve	(322,831)	(219,260)	(32,932)	(252,192)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (115,487)	$ (8,157,546)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

I/A

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

I/A

Smith Exhibit 1
Second Supplemental_S

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(29,080)	(b)	131,061	49,457	(c)	180,518
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		263,154		(174,137)	-		(174,137)
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		234,074		(24,510)	49,457		24,947
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 234,074		$ (141,098)	$ 49,457		$ (91,641)

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

Smith Exhibit 1
Page 4d

I/A

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Supplemental_S
Corrected

Smith Exhibit 1 Supplemental Rebuttal

Line No.	Description	Ref #	SUMMARY OF PROPOSED REVENUE ADJUSTMENTS: Application	Partial Settlement	Second Supplemental	Second Supplemental_S	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(96,523)	(96,523)	(96,289)	(96,289)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(173,156)	(147,750)	(196,524)	(196,524)
6	Net Revenue Increase		$ 463,619	$ 321,573	$ 346,979	$ 298,439	$ 298,439
7							

Line No.	Description	Ref #	CHANGE IN OP INCOME: Application	Partial Settlement	Second Supplemental	Second Supplemental_S	Total Adjs [1]		CHANGE IN RATE BASE: Application	Partial Settlement	Second Supplemental	Second Supplemental_S	Total Change [2]
8													
9													
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ -	$ -	$ (154,370)		$ -	$ -	$ -	$ -	$ -
11	Update fuel costs to proposed rate	NC-0200	10,955	-	-	-	(8,786)		-	-	-	-	-
12	Normalize for weather	NC-0300	(45,273)	-	-	-	(39,806)		-	-	-	-	-
13	Annualize revenues for customer growth	NC-0400	1,771	-	(2,771)	-	(2,525)		-	-	-	-	-
14	Eliminate unbilled revenues	NC-0500	9,086	-	-	-	9,086		-	-	-	-	-
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	-	-	128,571		(1,037,885)	-	-	-	(1,037,885)
16	Adjust O&M for executive compensation	NC-0700	1,843	124	-	-	1,967		-	-	-	-	-
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	-	-	(30,333)		-	-	-	-	-
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	-	-	(3,122)		-	-	-	-	-
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	(9)	(4,732)	-	(56,870)		1,326,826	(1,507)	139,224	-	1,329,312
20	Amortize deferred environmental costs	NC-1100	(81,419)	-	-	-	(73,775)		325,675	-	-	-	295,100
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	37	1,420	-	(1,802)		-	-	-	-	-
22	Normalize O&M labor expenses	NC-1300	15,060	3,009	(3,633)	-	15,476		-	-	-	-	-
23	Update benefits costs	NC-1400	2,351	-	-	-	4,885		-	-	-	-	-
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	-	-	4,756		-	-	-	-	-
25	Amortize rate case costs	NC-1600	(539)	-	-	-	(539)		2,051	(2,051)	-	-	-
26	Adjust aviation expenses	NC-1700	1,129	157	-	-	1,287		-	-	-	-	-
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	-	-	1,438		(64,423)	-	-	-	(64,423)
28	Adjust for Merger Related Costs	NC-1900	3,276	-	2	-	3,285		347	-	(53)	-	(157)
29	Amortize Severance Costs	NC-2000	17,952	-	-	-	18,547		17,899	(16,717)	-	-	-
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	-	-	2,183		-	-	-	-	-
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(2,433)	623	978	(2,104)		-	-	-	-	-
32	Adjust cash working capital	NC-2300	(122)	17	(9)	(7)	(94)		(27,013)	3,904	(2,116)	(1,069)	(20,500)
33	Adjust coal inventory	NC-2400	-	-	-	-	-		9,641	-	-	-	(11,603)
34	Adjust for credit card fees	NC-2500	(3,993)	-	-	-	(4,048)		-	-	-	-	-
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	-	-	(68,170)		(88,728)	-	-	-	(88,728)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	-	-	(4,424)		-	-	-	-	-
37	Adjust reserve for end of life nuclear costs	NC-2800	70	1,403	-	-	1,473		-	-	-	-	-
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	34,448	7	0	1,264		470,238	(531,121)	27	-	(66,408)
39	Adjust other revenue	NC-3000	(3,188)	-	-	-	(3,188)		-	-	-	-	-
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	-	-	180		-	-	-	-	-
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	-	-	-	(2,910)		(32,730)	-	-	-	42,550
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-	-	-		-	-	-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	4,299	-	-	(5,771)		24,624	(16,124)	-	-	3,488
44	Adjust Purchased Power	NC-3500	1,510	-	-	-	1,510		-	-	-	-	-
45	Correct Lead Lag	NC-3600	-	-	-	-	-		-	-	-	-	(8,580)
46	Amortize Prot EDIT	NC-3700	-	23,470	-	-	23,470		-	23,470	-	-	23,470
47	Remove certain Settlement Items	NC-3800	-	2,177	-	-	2,177		-	-	-	-	-
48	Normalize for storm costs	NC-3900	-	(7,145)	-	-	(7,145)		-	-	-	-	-
49													
50		Adjustments	$ (319,441)	$ 59,554	$ (9,094)	$ 971	$ (248,227)		$ 926,524	$ (540,146)	$ 137,082	$ (1,069)	$ 395,635
51													
52	Operating income	[3]	675,472	675,472	675,472	675,472	675,472	Rate base [4]	9,859,050	9,859,050	9,859,050	9,859,050	9,859,050
53	Total Adjustments		(319,441)	(240,104)	(249,198)	(248,227)	(248,227)	Total Adjustments	926,524	259,622	396,705	395,635	395,635
54	Adjusted Net Operating Income		356,031	435,367	426,273	427,244	427,244	Adjusted Rate Base	10,785,574	10,118,673	10,255,755	10,254,686	10,254,686
55													
56	Revenue Requirement Impact		417,313	(77,801)	11,880	(1,269)	324,280		79,408	(46,293)	11,749	(92)	33,908
			417,313	313,669	325,549	324,280	324,280		79,408	22,251	34,000	33,908	33,908

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

I/A

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 2
Second Supplemental_S
Corrected

Line No.	Description	NC RETAIL	Reference
1	Additional base revenue requirement	$ 389,438	Smith Exhibit 1 Second Supplemental_S
2	REVISED Annual EDIT Rider 1	7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback	(96,289)	Smith Exhibit 4 Second Supplemental_S corrected
4	Regulatory Asset and Liability Rider	(2,091)	Smith Exhibit 5
5	Subtotal	(90,998)	Sum L3 - L17
6	Net Revenue Increase	$ 298,439	

I/A

DUKE ENERGY PROGRESS, LLC
Reconciliation of Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 3
Second Supplemental_S

Line No.	Item			Amount
1	Revenue requirement increase per Company application			**585,961**
2		Revenue impact of Company adjustments through Settlement		(173,156)
3		Revenue impact of supplemental updates through May		25,406
4	Revenue requirement increase per Smith Exhibit 1 Second Supplemental		**$**	**438,211**
5				
6	Changes to reflect Intervenor Settlements:			
7	Ex 1	Adjust ROE from 10.3% to 9.75		(38,526)
8	Ex 1	Adjust D/E Ratio from 53/47 to 52/48		(8,348)
9	NC2200	Adjust synchronized interest expense		(1,277)
10	NC2300	Adjust cash working capital under present rates		(88)
11	NC2300	Adjust cash working capital under proposed rates		(535)
	Rounding			-
12	Total Revenue impact of changes		$	(48,774)
13				
14	Revenue Requirement per Smith Exhibit 1 Second Supplemental_S		**$**	**389,438**

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

			Federal EDIT - Unprotected, PP&E related NC Retail	Federal EDIT - Unprotected, non PP&E related NC Retail	NC EDIT NC Retail	Deferred Revenue NC Retail	Total NC Retail
			(A)	(B)	(C)	(D)	(E)
1	Regulatory Federal EDIT liabilIty including gross up on the books as of 12/31/2018, based on 2017 tax returns	[1]	$ (326,704)	$ 4,862	$ (23,726)		(345,568)
2	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2018-12/31/2018	[1]		$ (30,548)	$ -		(30,548)
3	Estimated transition of Protected to Unprotected Regulatory liability 1/1/2019-8/31/2020	[1]		$ (50,913)	$ -		(50,913)
4	Regulatory Federal EDIT liability including gross up and transition of Protected to Unprotected Regulatory liability as of 8/31/2020 (Sum of L1 to L3)	[1]	$ (326,704)	$ (76,598)	$ (23,726)	$ -	(427,028)
5	Adjustment to implement ASU 2018-02	[1]		$ (34)	$ -		(34)
6	Adjustment for Amended 2017 Federal Return	[1]	$ (415)				(415)
7	Deferred revenues related to 2017 Federal Tax Rate Change as of 12/31/2018	[1]				$ (108,392)	(108,392)
8	Other projected updates through 2/29/2020	[2]			$ (271)	$ (1,923)	(2,194)
9	Regulatory liabilIty for federal tax change including gross up for NC Retail, for Year 1 rider calculation (Sum of L4 to L8)		$ (327,119)	$ (76,631)	$ (23,998)	$ (110,315)	(538,063)
10	Years of rider amortization		20	5	5	2	
11	Annual amortization amount (L9 / L10)		$ (16,356)	$ (15,326)	$ (4,800)	$ (55,157)	(91,639)

[1] Excess deferred tax liability (EDIT) as of 12/31/2018 by jurisdiction, and forecast transition to new rates effective date between categories based on Tax analysis of ADIT.
Federal EDIT related to the federal tax changes booked to the 0254036 and 0254038 accounts is included in other Working Capital in the per books cost of service.
NC EDIT related to the NC state tax reduction deferred to the 0254150 account not included for recovery in NC EDIT rider approved in prior DEP NC rate case.
This NC EDIT is included in other Working Capital in the per books cost of service.
Revenues deferred for federal tax changes with accrued returns in the 0229010 account, are currently excluded from rate base in the per books COSS.

[2] Projected updates to the Federal and NC tax EDIT during 2019 by Tax
NORTH CAROLINA RETAIL, Page 3, Line 1 return accruals on deferred revenues in the 0229010 account projected through 2/29/2020.

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL
Excess Deferred Income Tax Rider Calculation
(Dollars in thousands)

Cost of Capital per Smith Exhibit 1	Ratio	Rate	After Tax Weighted Average Cost of Capital (WACC)
Debt	48.00%	4.11%	1.51%
Equity	52.00%	9.75%	5.07%
			6.58%
Statutory Tax Rate			23.17%
Retention factor for NCUC Fee, Uncollectibles			99.63%

Annual Rider Calculation

Year		Beginning Balance, Page 1, L9	Amortization - From Page 1, L: Federal EDIT - Unprotected, PP&E related	Federal EDIT - Unprotected, non PP&E related	NC EDIT	Deferred Revenue	Total Amortization	Ending Balance before Return	Average of Beginning and Ending Balance	EDIT Balance in Base Rates, Page 1, L1	Change in Regulatory Liability for Rider Return	Return for Rider	Rider Revenues	Rider Revenues NCUC Fee, Uncollectibles	
		(A)	(B)	(C)	(D)	(E)	(F) =(B)+(C)+(D)+[E]	(G) = (A) - (F)	(H) = ((A) + (G)) /2	(I)	(J) = (H) - (I)	(K) = (J) x After Tax WACC	(L) = (F) + (K)	(M) = (L) / Retention Factor	
Sep 20- Nov 21	1	(538,063)	(16,356)	(15,326)	(4,800)	(55,157)	(91,639)	(446,424)	($492,243)	(427,028)	($65,215)	($4,294)	(95,933)	(96,289)	
Dec 21- Nov 22	2	(446,424)	(16,356)	(15,326)	(4,800)	(55,157)	(91,639)	(354,784)	($400,604)	(427,028)	$26,424	$1,740	(89,899)	(90,232)	[1]
Dec 22- Nov 23	3	(354,784)	(16,356)	(15,326)	(4,800)	-	(36,482)	(318,303)	($336,544)	(427,028)	$90,485	$5,958	(30,524)	(30,637)	[1]
Dec 23- Nov 24	4	(318,303)	(16,356)	(15,326)	(4,800)	-	(36,482)	(281,821)	($300,062)	(427,028)	$126,966	$8,360	(28,121)	(28,225)	[1]
Dec 24- Nov 25	5	(281,821)	(16,356)	(15,326)	(4,800)	-	(36,482)	(245,339)	($263,580)	(427,028)	$163,448	$10,763	(25,719)	(25,814)	[1]

[1] The rider amounts for years 2 through 5 are shown for illustrative purposes only. Actual rider amounts will be filed each year with updates discussed in my testimony by September 30th for Commission approv

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
Smith Exhibit 4
For the test period ended December 31, 2018
NORTH CAROLINA RETAIL

	Deferred Revenue for Federal Tax Rate Change in account 0229010	NC Retail
1	Projected Changes in Deferred Revenue for Federal Tax Rate Change through Feb 2020	($1,923,073)

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

			North Carolina Retail Operations				
Line No.	Description	Total Company Per Books (a) (Col. 1)	Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,682,421	$ 3,657,503	$ (302,701)	$ 3,354,802	$ 408,933	$ 3,763,735
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,429,144	881,642	(33,473)	848,169		848,169
3	Purchased power	390,677	158,763	(1,965)	156,798		156,798
4	Other operation and maintenance expense	1,546,719	1,050,819	(187,359)	863,460	1,510	864,970
5	Depreciation and amortization	1,060,260	669,787	236,153	905,941		905,941
6	General taxes	153,362	102,197	2,381	104,578		104,578
7	Interest on customer deposits	8,643 (b)	7,971	-	7,971		7,971
8	EDIT Amortization	-	-	(30,548)	(30,548)	-	(30,548)
9	Net income taxes	150,622	112,986	(49,656)	63,330	94,163	157,494
10	Amortization of investment tax credit	(3,356)	(2,134)	(1,481)	(3,614)		(3,614)
11	Total electric operating expenses	4,736,071	2,982,032	(65,946)	2,916,085	95,673	3,011,759
12	Operating income	$ 946,351	$ 675,472	$ (236,755)	$ 438,717	$ 313,259	$ 751,976
13	Original cost rate base	$ 14,580,739	$ 9,859,050	$ 934,441 (d)	$ 10,793,491	$ 51,938 (f)	$ 10,845,429
14	Rate of return on North Carolina retail rate base		6.85%		4.06%		6.93%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3, Line 36
(d) From Page 4, Line 9
(e) From Page 2
(f) From Page 4d, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 3, Line 12.

I/A

Smith Exhibit 1
Second Settlement

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

				North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
Line No.	Description	Dec. 31, 2018 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	$ 8,108,191	48.00%	$ 5,180,876	4.04%	$ 209,564	$ 5,205,806	4.04%	$ 210,572
2	Members' equity (a)	8,717,931	52.00%	5,612,616	4.08%	229,153	5,639,623	9.60%	541,404
3	Total	$ 16,826,122	100.00%	$ 10,793,491 (b)		$ 438,717 (c)	$ 10,845,429 (b)		751,976
4	Operating income before increase (Line 3, Column 5)								438,717
5	Additional operating income required (Line 3 minus Line 4)								313,259
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								(234)
7	Regulatory fee (.1297%), Uncollectibles Rate (.2394%), and income taxes (23.1693%)								95,907
8	Additional revenue requirement								$ 408,933
9	Revenue Adjustments (d)								$ (146,897)
10	Net Increase								$ 262,036

-- Some totals may not foot or compute due to rounding.

Notes:
(a) Th equivalent of common equity for a limited liability company
(b) From Page 1, Line 12, Columns 4 and 6
(c) From Page 1, Line 11, Column 4
(d) From Smith Exhibit 2, Line 5

Smith Exhibit 1
Second Settlement

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
1	Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	-	(52,114)	-	(172,813)
1(D)	Annualize retail revenues for current rates- Supplemental	24,093	-	-	89	-	-	-	5,562	-	18,443
2	Update fuel costs to proposed rate	-	(12,574)	-	-	(1,684)	-	-	3,304	-	10,955
2(F)	Update fuel costs to proposed rate- Rebuttal	-	24,010	-	-	1,684	-	-	(5,953)	-	(19,741)
3	* Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	-	(13,653)	-	(45,273)
3(E)	Normalize for weather- Supplemental	4,882	(2,252)	-	18	-	-	-	1,649	-	5,467
4	* Annualize revenues for customer growth	5,182	2,857	-	19	-	-	-	534	-	1,771
4(J)	Annualize revenues for customer growth- Second Settlement	(13,548)	(8,812)	-	(50)	-	-	-	(1,086)	-	(3,600)
5	Eliminate unbilled revenues	11,826	-	-	-	-	-	-	2,740	-	9,086
6	Adjust for costs recovered through non-fuel riders	(27,830)	(18,522)	-	(136,112)	(58,446)	(6,458)	-	63,161	-	128,547
6(C)	Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	(31)	-	-	-	7	-	24
7	Adjust O&M for executive compensation	-	-	-	(2,399)	-	-	-	556	-	1,843
7(J)	Adjust O&M for executive compensation- Second Settlement	-	-	-	(187)	-	-	-	43	-	144
8	Annualize depreciation on year end plant balances	-	-	-	-	42,068	-	-	(9,747)	(1,481)	(30,841)
8(D)	Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	(661)	-	-	153	-	508
9	Annualize property taxes on year end plant balances	-	-	-	-	-	4,064	-	(942)	-	(3,122)
10	* Adjust for post test year additions to plant in service	-	-	-	-	70,469	6,600	-	(17,857)	-	(59,213)
10(J)	Adjust for post test year additions to plant in service- Second Settlement	-	-	-	-	(2,200)	(850)	-	707	-	2,344
11	* Amortize deferred environmental costs	-	-	-	-	105,972	-	-	(24,553)	-	(81,419)
11(J)	Amortize deferred environmental costs- Second Settlement	-	-	-	-	(12,949)	-	-	3,000	-	9,949
12	Annualize O&M non-labor expenses	-	-	-	1,311	-	-	-	(304)	-	(1,007)
12(I)	Annualize O&M non-labor expenses- Second Supplemental	-	-	-	1,034	-	-	-	(240)	-	(794)
13	* Normalize O&M labor expenses	-	-	-	(18,512)	-	(1,089)	-	4,542	-	15,060
13(I)	Normalize O&M labor expenses- Second Supplemental	-	-	-	(722)	-	181	-	126	-	416
14	Update benefits costs	-	-	-	(3,060)	-	-	-	709	-	2,351
14(D)	Update benefits costs- Supplemental	-	-	-	(3,298)	-	-	-	764	-	2,534
15	* Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	-	1,444	-	4,788
15(E)	Levelize nuclear refueling outage costs- Supplemental	-	-	-	42	-	-	-	(10)	-	(32)
16	* Amortize rate case costs	-	-	-	701	-	-	-	(162)	-	(539)
16(G)	Amortize rate case costs- Partial Settlement	-	-	-	-	-	-	-	-	-	-
17	Adjust aviation expenses	-	-	-	(1,452)	-	(18)	-	341	-	1,129
17(G)	Adjust aviation expenses- Partial Settlement	-	-	-	(205)	-	-	-	47	-	157

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT Amortization (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,479)	5	-	434	-	1,438
19	*	Adjust for Merger Related Costs	-	-	-	(4,039)	(172)	(53)	-	988	-	3,276
19(I)		Adjust for Merger Related Costs	-	-	-	-	(12)	-	-	3	-	10
20	*	Amortize Severance Costs	-	-	-	(23,366)	-	-	-	5,414	-	17,952
20(G)		Amortize Severance Costs- Partial Settlement	-	-	-	(774)	-	-	-	179	-	594
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	(2,183)	-	2,183
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	123	-	(123)
22(J)		Synchronize interest expense with end of period rate base- Second Settlement	-	-	-	-	-	-	-	264	-	(264)
23	*	Adjust cash working capital	-	-	-	-	-	-	-	122	-	(122)
23(J)		Adjust cash working capital- Second Settlement	-	-	-	-	-	-	-	(23)	-	23
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-	-
24(C)		Adjust coal inventory- Supplemental	-	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	-	(1,204)	-	(3,993)
25(F)		Adjust for credit card fees- Rebuttal	-	-	-	72	-	-	-	(17)	-	(55)
26		Adjust Depreciation for new rates	-	-	-	-	89,601	-	-	(20,760)	-	(68,841)
26(D)		Adjust Depreciation for new rates- Supplemental	-	-	-	-	(873)	-	-	202	-	671
27		Adjust vegetation management expenses	-	-	-	5,757	-	-	-	(1,334)	-	(4,424)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(91)	-	-	21	-	70
28(G)		Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	(1,826)	-	-	423	-	1,403
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,717	-	-	(10,129)	-	(33,588)
29(I)		Update deferred balance and amortize storm costs- Second Supplemental	-	-	-	-	(45,362)	-	-	10,510	-	34,852
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,413)	(181)	(1,032)	-	1,767	-	5,859
32(F)		Reflect retirement of Asheville Steam Generating Plant- Rebuttal	-	-	-	-	10,381	1,032	-	(2,644)	-	(8,769)
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	-	(1,144)	-	(3,794)
33(A)		Adjust for CertainTeed payment obligation- Supplemental	-	-	-	(4,939)	-	-	-	1,144	-	3,794
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,109	13,594	-	-	(4,565)	-	(15,138)
34(J)		Amortize deferred balance Asheville Combined Cycle- Second Settlement	-	-	-	(7,568)	(4,696)	-	-	2,842	-	9,423

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Settlement

Line No.	Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Wages Benefits Materials Etc. (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	EDIT 0.0000% (Col. 7)	Income Taxes 23.1693% (Col. 8)	Amortization of ITC (Col. 9)	Operating Income (Col. 10)
35	Adjust Purchased Power	-	-	(1,965)	-	-	-	-	455	-	1,510
36(E)	Correct Lead Lag- Supplemental	-	-	-	-	-	-	-	-	-	-
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	-	-	-	(30,548)	7,078	-	23,470
38(J)	Remove certain Settlement Items- Second Settlement	-	-	-	(2,834)	(8,700)	-	-	2,672	-	8,861
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	9,300	-	-	-	(2,155)	-	(7,145)
40(J)	Adjust Rate Base for EDIT- Second Settlement	-	-	-	-	-	-	-	-	-	-
41	Total adjustments - Original Filing	$ (318,129)	$ (46,419)	$ (1,965)	$ (177,306)	$ 301,368	$ 2,018	$ -	$ (74,904)	$ (1,481)	$ (319,441)
41(J)	Change from Application	15,428	12,946	-	(10,053)	(65,215)	363	(30,548)	25,249	-	82,686
42	Total adjustments	$ (302,701)	$ (33,473)	$ (1,965)	$ (187,359)	$ 236,153	$ 2,381	$ (30,548)	$ (49,656)	$ (1,481)	$ (236,755)

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

I/A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Settlement

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-	225,760	-	225,760
1(D)		Annualize retail revenues for current rates- Supplemental	-	-	-	-	-	-	-	-	(24,093)	-	(24,093)
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-	(14,311)	-	(14,311)
2(F)		Update fuel costs to proposed rate- Rebuttal	-	-	-	-	-	-	-	-	25,789	-	25,789
3	*	Normalize for weather	-	-	-	-	-	-	-	-	59,144	-	59,144
3(E)		Normalize for weather- Supplemental	-	-	-	-	-	-	-	-	(7,142)	-	(7,142)
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-	(2,314)	-	(2,314)
4(J)		Annualize revenues for customer growth- Second Settlement	-	-	-	-	-	-	-	-	4,703	-	4,703
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-	(11,869)	-	(11,869)
6		Adjust for costs recovered through non-fuel riders	(978,325)	158,734	(157,453)	(150,987)	90,146	-	-	(1,037,885)	(167,932)	(94,010)	(261,943)
6(C)		Adjust for costs recovered through non-fuel riders- Supplemental	-	-	-	-	-	-	-	-	(31)	6,423	6,392
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-	(2,408)	-	(2,408)
7(J)		Adjust O&M for executive compensation- Second Settlement	-	-	-	-	-	-	-	-	(188)	-	(188)
8		Annualize depreciation on year end plant balances		-	-	-	-	-	-	-	40,290	-	40,290
8(D)		Annualize depreciation on year end plant balances- Supplemental	-	-	-	-	-	-	-	-	(663)	-	(663)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-	4,079	-	4,079
10	*	Adjust for post test year additions to plant in service	1,845,936	(383,473)	-	(1,458)	(31,249)	-	(102,930)	1,326,826	77,355	120,182	197,537
10(J)		Adjust for post test year additions to plant in service- Second Settlement	(187,320)	195,347	-	20,220	(25,761)	-	-	2,486	(3,062)	(8,002)	(11,064)
11	*	Amortize deferred environmental costs	-	-	-	423,886	(98,212)	-	-	325,675	106,364	29,499	135,863
11(J)		Amortize deferred environmental costs- Second Settlement	-	-	-	(36,795)	8,525	-	-	(28,270)	(12,997)	(4,401)	(17,398)
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-	1,316	-	1,316
12(I)		Annualize O&M non-labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	1,038	-	1,038
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-	(19,674)	-	(19,674)
13(I)		Normalize O&M labor expenses- Second Supplemental	-	-	-	-	-	-	-	-	(544)	-	(544)
14		Update benefits costs	-	-	-	-	-	-	-	-	(3,071)	-	(3,071)
14(D)		Update benefits costs- Supplemental	-	-	-	-	-	-	-	-	(3,310)	-	(3,310)
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-	(6,255)	-	(6,255)
15(E)		Levelize nuclear refueling outage costs- Supplemental	-	-	-	-	-	-	-	-	42	-	42
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051	704	186	889
16(G)		Amortize rate case costs- Partial Settlement	-	-	-	(2,670)	619	-	-	(2,051)	-	(186)	(186)
17		Adjust aviation expenses	-	-	-	-	-	-	-	-	(1,475)	-	(1,475)
17(G)		Adjust aviation expenses- Partial Settlement	-	-	-	-	-	-	-	-	(206)	-	(206)

Smith Exhibit 1 Page 3 (cond)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Settlement

Line No.	Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)	Oper Inc Rev Req Impact (Col. 9)	R/B Rev Req Impact (Col. 10)	Total Rev Req Impact (Col. 11)
18	Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)	(1,878)	(5,437)	(7,315)
19	* Adjust for Merger Related Costs	-	347	-	-	-	-	-	347	(4,280)	31	(4,248)
19(I)	Adjust for Merger Related Costs	(558)	55	-	-	-	-	-	(504)	(12)	(45)	(57)
20	* Amortize Severance Costs	-	-	-	23,297	(5,398)	-	-	17,899	(23,453)	1,621	(21,832)
20(G)	Amortize Severance Costs- Partial Settlement	-	-	-	(23,297)	5,398	-	-	(17,899)	(777)	(1,621)	(2,398)
21	Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-	(2,851)	-	(2,851)
22	* Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-	160	-	160
22(J)	Synchronize interest expense with end of period rate base- Second Settlement	-	-	-	-	-	-	-	-	345	-	345
23	* Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)	160	(2,447)	(2,287)
23(J)	Adjust cash working capital- Second Settlement	-	-	-	4,952	-	-	-	4,952	(30)	585	555
24	Adjust coal inventory	-	-	9,641	-	-	-	-	9,641	-	873	873
24(C)	Adjust coal inventory- Supplemental	-	-	(21,244)	-	-	-	-	(21,244)	-	(1,852)	(1,852)
25	* Adjust for credit card fees	-	-	-	-	-	-	-	-	5,217	-	5,217
25(F)	Adjust for credit card fees- Rebuttal	-	-	-	-	-	-	-	-	72	-	72
26	Adjust Depreciation for new rates	-	(88,728)	-	-	-	-	-	(88,728)	89,933	(8,037)	81,896
26(D)	Adjust Depreciation for new rates- Supplemental	-	-	-	-	-	-	-	-	(876)	549	(327)
27	Adjust vegetation management expenses	-	-	-	-	-	-	-	-	5,779	-	5,779
28	Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-	(91)	-	(91)
28(G)	Adjust reserve for end of life nuclear costs- Partial Settlement	-	-	-	-	-	-	-	-	(1,833)	-	(1,833)
29	* Update deferred balance and amortize storm costs	-	-	-	612,045	(141,807)	-	-	470,238	43,879	42,594	86,473
29(I)	Update deferred balance and amortize storm costs- Second Supplemental	(68,639)	2,231	-	(612,045)	141,807	-	-	(536,647)	(45,530)	(48,198)	(93,728)
30	Adjust other revenue	-	-	-	-	-	-	-	-	4,165	-	4,165
31	Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-	(235)	-	(235)
32	* Reflect retirement of Asheville Steam Generating Plant	(287,052)	210,671	(7,002)	65,929	(15,275)	-	-	(32,730)	(7,654)	(2,965)	(10,619)
32(F)	Reflect retirement of Asheville Steam Generating Plant- Rebuttal	287,052	(210,671)	(73)	(1,339)	310	-	-	75,279	11,456	6,555	18,011
33	Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-	4,957	-	4,957
33(A)	Adjust for CertainTeed payment obligation- Supplemental	-	-	-	-	-	-	-	-	(4,957)	-	(4,957)
34	* Amortize deferred balance Asheville Combined Cycle	-	-	3,735	27,188	(6,299)	-	-	24,624	19,776	2,230	22,006
34(J)	Amortize deferred balance Asheville Combined Cycle- Second Settlement	-	-	(248)	(27,188)	6,299	-	-	(21,136)	(12,310)	(1,936)	(14,246)

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Settlement

Line No.	Description	EPIS	Accum Deprec	Materials & Supplies	Working Capital	ADIT	Operating Reserves	CWIP	Rate Base	Oper Inc Rev Req Impact	R/B Rev Req Impact	Total Rev Req Impact
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)
35	Adjust Purchased Power	-	-	-	-	-	-	-	-	(1,972)	-	(1,972)
36(E)	Correct Lead Lag- Supplemental	-	-	-	(8,580)	-	-	-	(8,580)	-	(724)	(724)
37(G)	Amortize Prot EDIT- Partial Settlement	-	-	-	30,548	(7,078)	-	-	23,470	(30,661)	1,981	(28,680)
38(J)	Remove certain Settlement Items- Second Settlement	-	-	-	-	-	-	-	-	(11,576)	-	(11,576)
39(G)	Normalize for storm costs- Partial Settlement	-	-	-	-	-	-	-	-	9,334	-	9,334
40(J)	Adjust Rate Base for EDIT- Second Settlement	-	-	-	-	538,063	-	-	538,063	-	45,407	45,407
41	Total adjustments - Original Filing	$ 580,558	$ (102,448)	$ (151,079)	$ 891,707	$ (189,284)	$ -	$ (102,930)	$ 926,524	$ 417,313	$ 78,189	$ 495,502
41(J)	Change from Application	30,535	(13,039)	(21,565)	(656,195)	668,182	-	-	7,917	(108,020)	668	(107,352)
42	Total adjustments	$ 611,093	$ (115,487)	$ (172,644)	$ 235,512	$ 478,898	$ -	$ (102,930)	$ 934,441	$ 309,293	$ 78,857	$ 388,150

-- Some totals may not foot or compute due to rounding.

Notes: * Identification required by NCUC Rule R1-17(b)

I/A

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003
2	Less: Accumulated depreciation and amortization	4b	(11,648,793)	(8,042,060)	(115,487)	(8,157,546)
3	Net electric plant		16,126,825	10,763,851	495,606	11,259,457
4	Add: Materials and supplies	4c	1,076,701	754,774	(172,644)	582,130
5	Working capital investment	4d	(642,895)	(375,172)	235,512	(139,660)
6	Less: Accumulated deferred taxes		(2,000,064)	(1,332,628)	478,898	(853,730)
7	Operating reserves		(82,759)	(54,705)	-	(54,705)
8	Construction work in progress	3	102,930	102,930	(102,930)	(0)
9	Total		$ 14,580,739	$ 9,859,050	$ 934,441	$ 10,793,491

-- Some totals may not foot or compute due to rounding.

I/A

Smith Exhibit 1
Second Settlement

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 16,551,690	$ 10,056,520	$ (179,365)	$ 9,877,155
2	Transmission Plant	2,746,389	1,643,263	264,402	1,907,665
3	Distribution Plant	6,944,764	6,052,263	433,108	6,485,371
4	General Plant	628,616	465,435	68,399	533,833
5	Intangible Plant	527,370	358,178	51,912	410,090
6	Subtotal	27,398,830	18,575,658	638,456	19,214,114
7	Nuclear Fuel (Net)	376,788	230,252	(27,363)	202,889
8	Total electric plant in service	$ 27,775,617	$ 18,805,911	$ 611,093	$ 19,417,003

-- Some totals may not foot or compute due to rounding.

Smith Exhibit 1
Page 4a

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,107,080)	$ (4,390,758)	$ (50,423)	$ (4,441,180)
2	Transmission Reserve	(816,198)	(488,611)	(27,693)	(516,304)
3	Distribution Reserve	(3,235,148)	(2,819,386)	26,382	(2,793,003)
4	General Reserve	(167,536)	(124,045)	(30,822)	(154,867)
5	Intangible Reserve	(322,831)	(219,260)	(32,932)	(252,192)
6	Total	$ (11,648,793)	$ (8,042,060)	$ (115,487)	$ (8,157,546)

7 The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:

No.	Description	Rate
8	Steam production plant	0.00%
9	Nuclear production plant	0.00%
10	Hydro production plant	0.00%
11	Other production plant	2.61%
12	Transmission plant	5.18%
13	Distribution plant	1.90%
14	General plant	Various
15	Intangible plant	20.00%

-- Some totals may not foot or compute due to rounding.

I/A

Smith Exhibit 1
Second Settlement

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations: Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 87,298	$ 53,347	$ (18,678) (a)	$ 34,669
2	Oil	113,740	69,506	-	69,506
3	Total fuel stock	201,037	122,853	(18,678)	104,174
4	Other electric materials and supplies and stores clearing	875,663	631,921	(153,966)	477,956
5	Total Materials and Supplies	$ 1,076,701	$ 754,774	$ (172,644)	$ 582,130

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

Smith Exhibit 1
Page 4c

I/A

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Settlement

Line No.	Description	Total Company Per Books (Col. 1)		North Carolina Retail Operations: Per Books (Col. 2)		Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)	Impact of Rev Incr (Col. 5)		With Rev Incr (Col. 6)
	Investor advanced funds:										
1	Operating funds per lead-lag study	238,679	(a)	160,141	(a)	(30,642)	(b)	129,499	51,938	(c)	181,437
2	Unamortized Debt	47,722		32,019		-		32,019	-		32,019
3	Regulatory Assets	(781,496)		(437,291)		266,154		(171,137)	-		(171,137)
4	Other	(10,529)		(13,453)		-		(13,453)	-		(13,453)
5	Total investor advanced funds	(505,624)		(258,584)		235,512		(23,072)	51,938		28,866
6	Less: customer deposits	(137,271)		(116,588)		-		(116,588)	-		(116,588)
7	Total working capital investment	$ (642,895)		$ (375,172)		$ 235,512		$ (139,660)	$ 51,938		$ (87,722)

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Angers Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects an increase in "operating funds per lead-lag study" for the impact of the revenue increase

I/A

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1219
SUPPLEMENTAL CHANGES TO OP INCOME AND RATE BASE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 1
Second Settlement

Smith Exhibit 1 Supplemental Rebuttal

SUMMARY OF PROPOSED REVENUE ADJUSTMENTS

Line No.	Description	Ref #	Application	Partial Settlement	Second Supplemental	Second Supplemental S	Second Settlement	Total Adjustments
1	Additional base revenue requirement	Smith Exhibit 1	$ 585,961	$ 585,961	$ 585,961	$ 585,961	$ 585,961	$ 585,961
2	REVISED Annual EDIT Rider 1	Smith Exhibit 3	7,381	7,381	7,381	7,381	7,381	7,381
3	Annual EDIT Rider 2 - Year 1 giveback	Smith Exhibit 4	(127,633)	(96,523)	(96,523)	(96,289)	(152,348)	(152,348)
4	Regulatory Asset and Liability Rider	Smith Exhibit 5	(2,091)	(2,091)	(2,091)	(2,091)	(2,091)	(2,091)
5	Revenue impact of Company update			(173,156)	(147,750)	(196,524)	(177,029)	(177,029)
6	Net Revenue Increase		$ 463,619	$ 321,573	$ 346,979	$ 298,439	$ 261,875	$ 261,875
7								

CHANGE IN OP INCOME

Line No.	Description	Ref #	Application	Partial Settlement	Second Supplemental	Second Supplemental S	Second Settlement	Total Adjs [1]
8								
9								
10	Annualize retail revenues for current rates	NC-0100	$ (172,813)	$ -	$ -	$ -	$ -	$ (154,370)
11	Update fuel costs to proposed rate	NC-0200	10,955	-	-	-	-	(8,786)
12	Normalize for weather	NC-0300	(45,273)	-	-	-	-	(39,806)
13	Annualize revenues for customer growth	NC-0400	1,771	-	(2,771)	-	696	(1,829)
14	Eliminate unbilled revenues	NC-0500	9,086	-	-	-	-	9,086
15	Adjust for costs recovered through non-fuel riders	NC-0600	128,547	-	-	-	-	128,571
16	Adjust O&M for executive compensation	NC-0700	1,843	124	-	-	20	1,987
17	Annualize depreciation on year end plant balances	NC-0800	(30,841)	-	-	-	-	(30,333)
18	Annualize property taxes on year end plant balances	NC-0900	(3,122)	-	-	-	-	(3,122)
19	Adjust for post test year additions to plant in service	NC-1000	(59,213)	(9)	(4,732)	-	-	(56,870)
20	Amortize deferred environmental costs	NC-1100	(81,419)	-	-	-	2,305	(71,470)
21	Annualize O&M non-labor expenses	NC-1200	(1,007)	37	1,420	-	-	(1,802)
22	Normalize O&M labor expenses	NC-1300	15,060	3,009	(3,633)	-	-	15,476
23	Update benefits costs	NC-1400	2,351	-	-	-	-	4,885
24	Levelize nuclear refueling outage costs	NC-1500	4,788	-	-	-	-	4,756
25	Amortize rate case costs	NC-1600	(539)	-	-	-	-	(539)
26	Adjust aviation expenses	NC-1700	1,129	157	-	-	-	1,287
27	Adjust for approved regulatory assets and liabilities	NC-1800	1,438	-	-	-	-	1,438
28	Adjust for Merger Related Costs	NC-1900	3,276	-	2	-	-	3,285
29	Amortize Severance Costs	NC-2000	17,952	-	-	-	-	18,547
30	Adjust NC income taxes for rate change	NC-2100	2,183	-	-	-	-	2,183
31	Synchronize interest expense with end of period rate base	NC-2200	(123)	(2,433)	623	978	1,717	(387)
32	Adjust cash working capital	NC-2300	(122)	17	(9)	(7)	(6)	(99)
33	Adjust coal inventory	NC-2400	-	-	-	-	-	-
34	Adjust for credit card fees	NC-2500	(3,993)	-	-	-	-	(4,048)
35	Adjust Depreciation for new rates	NC-2600	(68,841)	-	-	-	-	(68,170)
36	Adjust vegetation management expenses	NC-2700	(4,424)	-	-	-	-	(4,424)
37	Adjust reserve for end of life nuclear costs	NC-2800	70	1,403	-	-	-	1,473
38	Update deferred balance and amortize storm costs	NC-2900	(33,588)	34,448	7	0	-	1,264
39	Adjust other revenue	NC-3000	(3,188)	-	-	-	-	(3,188)
40	Adjust for change in NCUC Reg Fee	NC-3100	180	-	-	-	-	180
41	Reflect retirement of Asheville Steam Generating Plant	NC-3200	5,859	-	-	-	-	(2,910)
42	Adjust for CertainTeed payment obligation	NC-3300	(3,794)	-	-	-	-	-
43	Amortize deferred balance Asheville Combined Cycle	NC-3400	(15,138)	4,299	-	-	56	(5,715)
44	Adjust Purchased Power	NC-3500	1,510	-	-	-	-	1,510
45	Correct Lead Lag	NC-3600	-	-	-	-	-	-
46	Amortize Prot EDIT	NC-3700	-	23,470	-	-	-	23,470
47	Remove certain Settlement Items	NC-3800	-	2,177	-	-	6,684	8,861
48	Normalize for storm costs	NC-3900	-	(7,145)	-	-	-	(7,145)
49	Adjust Rate Base for EDIT	NC-4000	-	-	-	-	-	-
50								
51		Adjustments	$ (319,441)	$ 59,554	$ (9,094)	$ 971	$ 11,472	$ (236,755)
52								
53	Operating income	[3]	675,472	675,472	675,472	675,472	675,472	675,472
54	Total Adjustments		(319,441)	(240,104)	(249,198)	(248,227)	(236,755)	(236,755)
55	Adjusted Net Operating Income		356,031	435,367	426,273	427,244	438,717	438,717
56								
57	Revenue Requirement Impact		417,313	(77,801)	11,880	(1,269)	(14,987)	309,293
			417,313	313,669	325,549	324,280	309,293	309,293

CHANGE IN RATE BASE

Line No.		Application	Partial Settlement	Second Supplemental	Second Supplemental S	Second Settlement	Total Change [2]
10		$ -	$ -	$ -	$ -	$ -	$ -
11		-	-	-	-	-	-
12		-	-	-	-	-	-
13		-	-	-	-	-	-
14		-	-	-	-	-	-
15		(1,037,885)	-	-	-	-	(1,037,885)
16		-	-	-	-	-	-
17		-	-	-	-	-	-
18		-	-	-	-	-	-
19		1,326,826	(1,507)	139,224	-	-	1,329,312
20		325,675	-	-	-	2,305	297,405
21		-	-	-	-	-	-
22		-	-	-	-	-	-
23		-	-	-	-	-	-
24		-	-	-	-	-	-
25		2,051	(2,051)	-	-	-	-
26		-	-	-	-	-	-
27		(64,423)	-	-	-	-	(64,423)
28		347	-	(53)	-	-	(157)
29		17,899	(16,717)	-	-	-	-
30		-	-	-	-	-	-
31		-	-	-	-	-	-
32		(27,013)	3,904	(2,116)	(1,069)	(1,562)	(22,061)
33		9,641	-	-	-	-	(11,603)
34		-	-	-	-	-	-
35		(88,728)	-	-	-	-	(88,728)
36		-	-	-	-	-	-
37		-	-	-	-	-	-
38		470,238	(531,121)	27	-	-	(66,408)
39		-	-	-	-	-	-
40		-	-	-	-	-	-
41		(32,730)	-	-	-	-	42,550
42		-	-	-	-	-	-
43		24,624	(16,124)	-	-	-	3,488
44		-	-	-	-	-	-
45		-	-	-	-	-	(8,580)
46		-	23,470	-	-	-	23,470
47		-	-	-	-	-	-
48		-	-	-	-	-	-
49		-	-	-	-	538,063	538,063
51		$ 926,524	$ (540,146)	$ 137,082	$ (1,069)	$ 538,806	$ 934,441
53	Rate base [4]	9,859,050	9,859,050	9,859,050	9,859,050	9,859,050	9,859,050
54	Total Adjustments	926,524	259,622	396,705	395,635	934,441	934,441
55	Adjusted Rate Base	10,785,574	10,118,673	10,255,755	10,254,686	10,793,491	10,793,491
57		78,189	(45,583)	11,568	(90)	45,470	78,857
		78,189	21,909	33,478	33,388	78,857	78,857

[1] Smith Exhibit 1, page 3, Column 9
[2] Smith Exhibit 1, page 3 (continued), Column 8-11
[3] Smith Exhibit 1, page 1, Line 11
[4] Smith Exhibit 1, page 1, Line 12

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0400
Second Settlement

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro forma annualizes revenue, fuel expense, operation and maintenance expense, and income taxes to reflect changes in the number of customers and usage per customer during the test period.

The impact to revenue was determined as follows:

To determine the additional revenue requirement resulting from customer growth, the monthly increase in number of customers was multiplied by the applicable average monthly kWh consumption per customer to derive the annualized change in kWh consumption based on the number of customers at the end of the test period.

The impact to fuel expense was determined by multiplying the 'Customer growth adjustment to KWH sales - NC kWh adjustment' by the most recent approved fuel rate (excluding EMF).

The impact to other operation and maintenance expense is determined by multiplying the impact to revenue by the statutory regulatory fee percentage rate and the uncollectibles rate.

The impact to income taxes was determined by multiplying taxable income by the statutory tax rate.

This adjustment updates revenues to reflect customer growth experienced beyond the test period, through July 2019. The underlying calculations reflect the same methods used in the Company's rebuttal testimony as explained by Company Witness Pirro in Docket E-2 Sub 1142.

October update

Updated NC-0403 for weather impacts in NC-300 and customer growth information through October 2019

November update

Updated NC-0403 for weather impacts in NC-300 and customer growth information through November 2019

December update

Updated NC-0403 for weather impacts in NC-300 and customer growth information through December 2019
NC-0404 was adjusted to calculate Residential ¢ / kWh excluding the Basic Customer Charge

January update

Updated NC-0403 for weather impacts in NC-300 and customer growth information through January 2020

February update

NC-0402 and NC-0403 now reflect separate adjustments for Customer Growth and Usage
Updated NC-0403 for weather impacts in NC-300 and customer growth information through February 2020
NC-0404 was adjusted to reflect the ¢ / kWh both with and excluding the Basic Customer Charge

May update

Updated customer growth and usage kWh through May 2020

Second Settlement

Adjustment to reduce May update by 75% per settlement agreement

Smith Second Settlement Exhibit 1

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0400
Second Settlement

Line No.	Description	Source	Total NC Retail Second Settlement	Total NC Retail Second Supplemental	Total NC Retail Application	Total NC Retail Change
1			Second Settlement	Second Supplemental	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue	NC-0401	$ (8,366)	$ (10,443)	$ 5,182	(13,548)
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation	NC-0401	(5,955)	(7,118)	2,857	(8,812)
9	Purchased power		-	-	-	-
10	Other operation and maintenance expense	NC-0401	(31)	(39)	19	(50)
11	Depreciation and amortization		-	-	-	-
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes	NC-0401	(551)	(761)	534	(1,086)
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	(6,537)	(7,918)	3,411	(9,948)
18						
19	Operating income	L4 - L17	$ (1,829)	$ (2,525)	$ 1,771	$ (3,600)
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					
24						
25						
26	**Pro Formas Impacting Rate Base Line Items**					
27						
28	Electric plant in service		$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-
31						
32	Add:					
33	Materials and supplies		-	-	-	-
34	Working capital investment		-	-	-	-
35						
36						
37	Less:					
38	Accumulated deferred taxes		-	-	-	-
39	Operating reserves		-	-	-	-
40						
41						
42	Construction work in progress		-	-	-	-
43						
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -
45						
46	Note:					
47	Rate Base: positive number increases rate base / negative number decreases rate base					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0401
Second Settlement

Line No.	Description	Residential	Small General Service	Medium General Service	Large General Service	SI	Area Service Lighting	Sports Field Lighting Service	Street Lighting Service	Traffic Service Signal	Total NC Retail	
1						NCSI		NCSFL	NCSLS	NCTSS		
2	Customer growth and usage Revenue adjustment - Feb	$ 9,029	$ (3,886)	$ (10,755)	$ 3,466	$ (321)	$ -	$ 19	$ 299	$ (10)	$ (2,159)	
3	Customer growth and usage Revenue adjustment - May	25,674	(7,252)	(32,527)	3,830	(994)	-	(16)	855	(4)	(10,435)	
4	May Increase	$ 16,645	$ (3,366)	$ (21,772)	$ 364	$ (673)	$ -	$ (35)	$ 557	$ 6	$ (8,276)	
5	75% of May increase	12,484	(2,525)	(16,329)	273	(505)	-	(26)	417	4	(6,207)	
6	Customer growth and usage Revenue adjustment - per settlement	$ 21,513	$ (6,410)	$ (27,084)	$ 3,739	$ (826)	$ -	$ (7)	$ 716	$ (6)	$ (8,366)	[1]
7												
8	Impact to fuel - Feb	$ 1,346	$ (1,298)	$ (3,621)	$ 1,161	$ (80)	$ -	$ 2	$ 21	$ (3)	$ (2,471)	
9	Approved fuel and fuel related costs ¢/kWh (excluding EMF)	2.326	2.499	2.456	2.054	2.456	2.217	2.217	2.217	2.217		[2]
10	Customer growth and usage adjustment to kWh sales	210,975,729	(93,344,303)	(439,354,341)	62,259,064	(9,654,269)	-	(104,146)	2,772,245	(48,762)	(266,498,784)	[1]
11	Impact to fuel - May (L9 x (L10 / 100,000))	$ 4,907	$ (2,333)	$ (10,791)	$ 1,279	$ (237)	$ -	$ (2)	$ 61	$ (1)	$ (7,116)	
12	May Increase	3,561	(1,035)	(7,169)	118	(158)	-	(5)	40	2	(4,645)	
13	75% of May increase	2,671	(776)	(5,377)	89	(118)	-	(4)	30	1	(3,484)	
14	Impact to fuel - per settlement (L8 + L13)	$ 4,017	$ (2,074)	$ (8,998)	$ 1,249	$ (198)	$ -	$ (1)	$ 51	$ (2)	$ (5,955)	
15												
16	Calculation of NCUC Regulatory Fee and Uncollectible											
17	Uncollectible rate	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	0.002394	[3]
18	Statutory regulatory fee percentage rate	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	0.001297	[4]
19	Impact to O&M ((L17 + L18) x L6)	$ 79	$ (24)	$ (100)	$ 14	$ (3)	$ -	$ (0)	$ 3	$ (0)	$ (31)	
20												
21	Taxable income (L6 - L14 - L19)	$ 17,417	$ (4,313)	$ (17,986)	$ 2,476	$ (625)	$ -	$ (6)	$ 662	$ (4)	$ (2,380)	
22												
23	Statutory tax rate	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	[5]
24	Impact to income taxes (L21 x L23)	$ 4,035	$ (999)	$ (4,167)	$ 574	$ (145)	$ -	$ (1)	$ 153	$ (1)	$ (551)	
25												
26	Impact to operating income (L21 - L24)	$ 13,381	$ (3,314)	$ (13,819)	$ 1,902	$ (480)	$ -	$ (5)	$ 508	$ (3)	$ (1,829)	

[1] NC-0402 - Calculation of Customer Growth and Usage Revenue Adjustment
[2] NC-0202 - NC Billed Fuel Factors (with EMF and EMF Interest Increment/Decrement for approved cost factors), Line 8
[3] NC-0105 - 2018 Uncollectibles Rate, Line 4
[4] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate - Adjusted, Docket No. M-100, Sub 142, Line 3
[5] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC | NC-0402a
Docket No. E-2, Sub 1219 | Second Settlement
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

Calculation of Customer Growth Adjustment

Line No.	Rate Schedule	NC Retail KWH Adjustment (a)	[1]	Cents Per kWh (b)	[2]	Revenue Adjustment (c) = ((a) x (b) / 100,000)
1	Residential	561,198,538		8.85		$ 49,654
2	Residential excl. TOU	550,471,121		8.85		48,721
3	Residential TOU	10,727,417		8.70		933
4						
5	Small General Service	39,079,080		10.83		$ 4,231
6	SGS excl. Constant Load Rate	37,664,616		10.81		4,073
7	SGS Constant Load Rate	1,414,464		11.20		158
8						
9	Medium General and Seasonal and Intermittent Service	105,085,689		7.66		$ 8,048
10	Medium General Service excl. Time of Use	44,209,854		8.73		3,860
11	Medium General Service Time of Use	58,616,356		6.72		3,941
12	Seasonal and Intermittent Service	2,259,479		10.95		247
13						
14	Large General Service	101,703,976		6.14		$ 6,247
15	Large General Service excl. Time of Use and Real Time Pricir	30,755,841		6.92		2,129
16	Large General Service Time of Use	42,289,282		6.29		2,662
17	Large General Service Real Time Pricing	28,658,852		5.08		1,456
18						
19	Sports Field Lighting Service	9,130		17.81		2
20	Street Lighting Service	2,772,245		30.84		855
21	Traffic Signal Service	(48,762)		9.15		(4)
22						
23	Total kWh Adjustment (L1 through L21)	809,799,895				
24						
25						
26	NC Residential Change in number of customers	# of Customers	[3]	BCC	[4]	
27	Residential	489,051		$ 14.00		$ 6,847
28	Residential TOU	9,530		$ 16.85		$ 161
29						
30						76,041

[1] NC-0403 - Customer Growth Adjustment to KWH Sales, col (d)
[2] NC-0404 - Present Revenue Annualized and KWH Sales - NC Retail, c/kWh. Residential uses ¢ / kWh excluding BCC.
[3] Source Rate Design Regression Analysis
[4] Basic Customer Charge per Tariffs - Pirro Exhibit 1: RES-60 $14.00, R-TOU-60 $16.85, and R-TOUD-60 $16.85

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0402b
Second Settlement

Calculation of Customer Usage Revenue Adjustment

Line No.	Rate Schedule	NC Retail KWH Adjustment (a)	[1]	Cents Per kWh (b)	[2]	Revenue Adjustment (c) = ((a) x (b) / 100,000)
1	Residential	(350,222,809)		8.85	$	(30,987)
2	Residential excl. TOU	(343,528,233)		8.85		(30,405)
3	Residential TOU	(6,694,576)		8.70		(582)
4						
5	Small General Service	(132,423,383)		8.67	$	(11,483)
6	SGS excl. Constant Load Rate	(127,630,328)		8.76		(11,177)
7	SGS Constant Load Rate	(4,793,055)		6.39		(306)
8						
9	Medium General and Seasonal and Intermittent Service	(554,094,299)		7.50	$	(41,570)
10	Medium General Service excl. Time of Use	(233,109,077)		8.53		(19,884)
11	Medium General Service Time of Use	(309,071,473)		6.61		(20,445)
12	Seasonal and Intermittent Service	(11,913,748)		10.42		(1,241)
13						
14	Large General Service	(39,444,912)		6.13	$	(2,417)
15	Large General Service excl. Time of Use and Real Time Pricir	(11,928,358)		6.90		(823)
16	Large General Service Time of Use	(16,401,493)		6.28		(1,029)
17	Large General Service Real Time Pricing	(11,115,061)		5.08		(564)
18						
19	Sports Field Lighting Service	(113,276)		15.46		(18)
20	Street Lighting Service	-		30.84		-
21	Traffic Signal Service	-		9.15		-
22						
23	Total kWh Adjustment (L1 through L21)	(1,076,298,679)				(86,475)

[1] NC-0403 - Customer Growth Adjustment to KWH Sales, col (d)
[2] NC-0404 - Present Revenue Annualized and KWH Sales - NC Retail, c/kWh. Residential uses ¢ / kWh excluding BCC.

Smith Second Settlement Exhibit 1

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0403
Second Settlement

Customer Growth Adjustment to KWH Sales

Line No.	(a) Rate Schedule	(b) COS Category	(c) NC Proposed Customer Growth kWh Adjustment	(d) NC Proposed Change in Usage kWh Adjustment	(e) NC Proposed KWH Adjustment [1]		(f) Adj by COS Schedule	(f) Adj by COS Schedule	COS Schedules	(g) Service Bases 12/31/2018 C1ALL	Allocator [2]
1											
2	NC Residential	Residential	561,198,538	(350,222,809)	210,975,729	RES, RET	550,471,121	(343,528,233)	NCRES	NCRES	1,177,050
3							10,727,417	(6,694,576)	NCRET	NCRET	22,938
4	NC General:									NCSGS	160,062
5	General Service Small	Small General Service	39,079,080	(132,423,383)	(93,344,303)	SGS, SGSTCLR	37,664,616	(127,630,328)	NCSGS	NCSGSTCLR	6,011
6	General Service Medium	Medium General Service	105,085,689	(554,094,299)	(449,008,610)	MGS, SGS-TOU,SI	1,414,464	(4,793,055)	NCSGSTCLR	NCSGTM	22,077
7	Total General		144,164,769	(686,517,682)	(542,352,913)		58,616,356	(309,071,473)	NCSGTM	NCMGS	16,651
8							44,209,854	(233,109,077)	NCMGS	NCSI	851
9							2,259,479	(11,913,748)	NCSI	NCLGS	88
10	NC Lighting:									NCLGT	121
11	Street Lighting	Lighting	2,772,245	-	2,772,245	SLS/SLR	2,772,245	-	NCSLS	NCRTP	82
12	Sports Field Lighting	Lighting	9,130	(113,276)	(104,146)	SFLS	9,130	(113,276)	NCSFL	NCTSS	780
13	Traffic Signal Service	Lighting	(48,762)	-	(48,762)	TSS/TFS	(48,762)	-	NCTSS	NCALS	0
14	Total Street Lighting		2,732,613	(113,276)	2,619,336					NCSLS	1,578
15										NCSFL	78
16	NC Industrial:										1,408,367
17	I - Textile	Large General Service	-	-	-		30,755,841	(11,928,358)	NCLGS		
18	I - Nontextile	Large General Service	101,703,976	-	101,703,976	LGS incl. TOU & RTP	42,289,282	(16,401,493)	NCLGT		
19	I - Textile & Nontextile	Large General Service	-	(39,444,912)	(39,444,912)		28,658,852	(11,115,061)	NCRTP		
20	Total Industrial		101,703,976	(39,444,912)	62,259,064						
21											
22							809,799,895	(1,076,298,679)			
23	Total		809,799,895	(1,076,298,679)	(266,498,784)						

Notes:
[1] Information provided by Rate Design.
[2] Regression using number of service bases, and schedules in proposed adjustment per Rate Design

Smith Second Settlement Exhibit 1

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Annualize revenues for customer growth
For the test period ended December 31, 2018

NC-0404
Second Settlement

Present Revenue Annualized and KWH Sales - NC Retail

Line No.	COS Category	Description	NORTH CAROLINA RETAIL: Present Revenue Annualized [1]	Basic Customer Charge (BCC)	Present Revenue Excluding BCC	Per Book kWh Sales [2]	All-Inclusive ¢ / kWh	w/o BCC ¢ / kWh
1								
2	Residential	RES - RESIDENTIAL SERVICE	$ 1,627,945,892	$ (197,751,086)	$ 1,430,194,806	16,158,859,096	10.07	8.85
3		R-TOUD - RESIDENTIAL SERVICE TIME-OF-USE	37,486,504	(4,041,968)	33,444,536	451,040,840		
4		R-TOU - RESIDENTIAL SERVICE ALL-ENERGY TIME-OF-USE	5,576,511	(694,079)	4,882,432	56,146,653	9.93	8.70
5	**Residential Sum**		$ 1,671,008,906	$ (202,487,133)	$ 1,468,521,774	16,666,046,589		
6	Small General Service	SGS - SMALL GENERAL SERVICE	210,976,543	$ (40,117,843)	$ 170,858,700	1,950,982,004	10.81	8.76
7		SGS-TOU-CLR - SMALL GENERAL SERVICE TIME-OF-USE CONSTANT LOAD RATE	3,539,804	(1,520,432)	2,019,372	31,614,397	11.20	6.39
8	**Small General Service Sum**		$ 214,516,347	$ (41,638,275)	$ 172,878,072	1,982,596,401		
9	Medium General Service	APH-TES - AGRICULTURAL POST-HARVEST SERVICE	133,640	$ (1,281)	$ 132,359	2,065,800		
10		CH-TOUE - CHURCH SERVICE EXPERIMENTAL TIME-OF-USE	1,173,027	(95,984)	1,077,043	8,706,511		
11		CSE - CHURCH AND SCHOOL SERVICE	193,536	(14,938)	178,598	1,373,440		
12		CSG - CHURCH AND SCHOOL SERVICE	4,336	(342)	3,994	25,680		
13		MGS - MEDIUM GENERAL SERVICE	242,144,278	(5,603,638)	236,540,640	2,773,108,650	8.73	8.53
14		SGS-TES - SMALL GENERAL SERVICE THERMAL ENERGY STORAGE	1,345,435	(6,090)	1,339,345	21,819,600		
15		SGS-TOU - SMALL GENERAL SERVICE TIME-OF-USE	562,838,889	(9,050,665)	553,788,224	8,371,865,197	6.72	6.61
16	**Medium General Service Sum**		$ 807,833,140	$ (14,772,938)	$ 793,060,202	11,178,964,878		
17	Large General Service	LGS - LARGE GENERAL SERVICE	79,000,414	$ (219,986)	$ 78,780,428	1,141,204,433	6.92	6.90
18		LGS-RTP - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING)	-	-	-	9,861,252		
19		LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	290,057,172	(187,226)	289,869,945	5,708,044,202	5.08	5.08
20		LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	100,616,525	(282,041)	100,334,484	1,598,681,135	6.29	6.28
21	**Large General Service Sum**		$ 469,674,111	$ (689,254)	$ 468,984,857	8,457,791,022		
22	Other	ALS - AREA LIGHTING SERVICE	62,316,881	$ -	$ 62,316,881	267,795,639		
23		SFLS - SPORTS FIELD LIGHTING SERVICE	202,072	(26,622)	175,450	1,134,908	17.81	15.46
24		SLS - STREET LIGHTING SERVICE	26,250,749	-	26,250,749	85,107,971	30.84	
25		TSS - TRAFFIC SIGNAL SERVICE	434,956	-	434,956	4,754,792	9.15	
26	**Other Sum**		$ 89,204,659	$ (26,622)	$ 89,178,037	358,793,310		
27	Seasonal Intermittent	SI - SEASONAL OR INTERMITTENT SERVICE	4,715,715	(228,386)	4,487,329	43,075,313	10.95	10.42
28	**Seasonal Intermittent Sum**		$ 4,715,715	$ (228,386)	$ 4,487,329	43,075,313		
29	Grand Total		$ 3,256,952,878	$ (259,842,608)	$ 2,997,110,271	38,687,267,513		

[1] NC-0102 - Column c
[2] NC-0302 Sum of kWh

Duke Energy Progress, LLC | NC-0700
Docket No. E-2, Sub 1219 | Narrative
Adjust O&M for executive compensation | Second Settlement
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro-forma adjusts operation and maintenance expense and income taxes for officers' compensation.

The impact to operation and maintenance expense is determined as follows:
Eliminate 50% of the compensation of the Chief Executive Officer (CEO), Chief Operating Officer (COO), Chief Financial Officer (CFO), Chief Legal Officer (CLO) and Customer and Delivery Operations and President, Carolinas Region allocated to Duke Energy Progress in the test period.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

Settlement
Executive fringe benefits removed as agreed to in Public Staff Settlement

Second Settlement
Updated annual Salaries of Top 5 officers as of May 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust O&M for executive compensation
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0700
Second Settlement

Line No.	Description	Source	NC Retail			
1			Second Settlement	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue		$ -	$ -	$ -	$ -
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation		-	-	-	-
9	Purchased power and net interchange		-	-	-	-
10	Wages, benefits, materials, etc.	NC-0701	(2,586)	(2,560)	(2,399)	(187)
11	Depreciation and amortization		-	-	-	-
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes	NC-0701	599	593	556	43
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	(1,987)	(1,967)	(1,843)	(144)
18						
19	Operating income	L4 - L17	$ 1,987	$ 1,967	$ 1,843	$ 144
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust O&M for executive compensation
For the test period ended December 31, 2018
(Dollars in thousands)

NC-0701
Settlement

Line No.	Description		CEO and Other Group Execs	
1				
2				
3	Compensation charged to Duke Energy Progress - Annual Salary as of May 2020	$	7,324	[1]
4	Executive fringe benefits agreed to in PS Settlement		486	[5]
5	Compensation charged to A&G	$	7,811	[1]
6				
7				
8	NC Retail Allocation Factor - Wage and Salary Related Items		66.2120%	[2]
9	NC retail compensation (L5 x L8)	$	5,172	
10	Exclusion percentage		50.00%	[3]
11	Impact to O&M (-L9 x L10)	$	(2,586)	
12				
13	Statutory tax rate		23.1693%	[4]
14				
15	Impact to income taxes (-L11 x L13)	$	599	
16				
17	Impact to operating income (-L11 - L15)	$	1,987	

[1] Information provided by Duke Energy Corporate Accounting. Updated annual salary for 2020.
[2] NC Retail Allocation Factor - LAB
[3] The percentage of compensation for the top five executive's compensation to be eliminated from the test year.
[4] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[5] Dorgan Stipulation Exhibit 1, Schedule 3-1(i), Line 2

Duke Energy Progress, LLC NC-1100
Docket No. E-2, Sub 1219 Second Settlement
Amortize deferred environmental costs
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts amortization expense, income taxes and rate base for the amortization of deferred environmental costs related to the removal of coal ash.

The impact to depreciation expense reflects a 5 year amortization of deferred coal ash costs. The balance of the deferral is projected through August 31, 2020. The estimated cost of removal related to the active and retired fossil plants that has already been collected from customers through depreciation rates is removed from the balance.

The impact to Rate Base includes the additional deferred costs through February of 2020 and additional ADIT on the deferred balance change.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

October update:

Updated Non ARO Spend and ARO spend with actuals through October 2019.

November update:

Updated Non ARO Spend and ARO spend with actuals through November 2019.

December update:

Updated Non ARO Spend and ARO spend with actuals through December 2019.

January update:

Updated actuals through January 2020 on NC 1103 and NC 1105; incorporated ADIT into the plant return calculation on NC 1105; added tab NC 1110 which estimates ADIT related to Non ARO Projects

February update:

Updated actuals through February 2020 on NC 1103, NC 1105, and NC 1110

Second Settlement

Adjust NC-1101 to reflect an 8-year amortization of Non-ARO costs

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1100
Second Settlement

Line No.	Description	Source	Total NC Retail			
1			Second Settlement	February	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue		$ -	$ -	$ -	$ -
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation		-	-	-	-
9	Purchased power and net interchange		-	-	-	-
10	Wages, benefits, materials, etc.		-	-	-	-
11	Depreciation and amortization	NC-1101	93,023	96,023	105,972	(12,949)
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes	NC-1101	(21,553)	(22,248)	(24,553)	3,000
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	71,470	73,775	81,419	(9,949)
18						
19	Operating income	L4 - L17	$ (71,470)	$ (73,775)	$ (81,419)	$ 9,949
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					
24	**Pro Formas Impacting Rate Base Line Items**					
25						
26	Electric plant in service		$ -	$ -	$ -	$ -
27	Accumulated depreciation and amortization		-	-	-	-
28	Electric plant in service, net	Sum L26 through L27	-	-	-	-
29						
30	Add:					
31	Materials and supplies		-	-	-	-
32	Working capital investment	NC 1801 L26	387,091	384,091	423,886	(36,795)
33	Plant held for future use		-	-	-	-
34						
35	Less:					
36	Accumulated deferred taxes	NC 1801 L28	(89,686)	(88,991)	(98,212)	8,525
37	Operating reserves		-	-	-	-
38	Customer deposits		-	-	-	-
39						
40	Construction work in progress		-	-	-	-
41						
42	Total impact to rate base	Sum L28 through L40	$ 297,405	$ 295,100	$ 325,675	$ (28,270)
43						
44	Note:					
45	Rate Base: positive number increases rate base / negative number decreases rate base					

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC-1101
Second Settlement

Line No.	Description	Total Coal Ash ARO NC Retail	Total Coal Ash Non ARO NC Retail	Total NC Retail
1				
2	Projected Ending Balance at August 31, 2020	$ 440,115 [1]	$ 39,999 [2]	$ 480,114
3				
4	Balance for Amortization	$ 440,115	$ 39,999	$ 480,114
5				
6	Years to Amortize	5	8	
7				
8	Annual amortization (L4/L6) before penalty	$ 88,023	$ 5,000	$ 93,023
9				
10	Statutory tax rate			23.1693% [3]
11				
12	Impact to income taxes (-L4 x L6)			$ (21,553)
13				
14	Impact to operating income (-L8 - L12)			$ (71,470)
15				
16	Impact to Rate Base			
17				
18	Projected August 31 2020 Balance for Rate Base (L2)	$ 440,115	$ 39,999	$ 480,114
19	Less 12 months Coal Ash Deferral Amortization (-L8)	(88,023)	(5,000)	(93,023)
20	Projected coal ash def bal after one year of amortization (L18 + L19)	$ 352,092	$ 34,999	$ 387,091
21				
22	Deferred tax rate	23.1693%	23.1693%	
23	Impact to accumulated deferred income tax (-L20 x L22)	$ (81,577)	$ (8,109)	$ (89,686)
24				
25	Impact to rate base (L20 + L23)	$ 270,515	$ 26,890	$ 297,405

[1] NC-1102 - Deferral Col (s) Line 40
[2] NC-1104 - Deferral Col (r) Line 65
[3] NC-0104 - 2019 Composite Tax rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC-1102
Second Settlement

	After Tax LTD Rate	After Tax Equity Rate	
2017	1.3519%	5.4060%	[5]
2018 Jan - Feb	1.6431%	5.4060%	[5]
2018 Mar - Dec	1.4871%	5.1480%	[5]
2019	1.4936%	5.1480%	[5]
2020	1.4936%	5.1480%	[5]

Line No.		(a) System Spend [1]	(b) Active Plant COR Offset [2]	(c) Retired Coal Ash Plant COR Offset [2]	ENERGY (d) % to NC [3]	Duke Energy Progress Coal Ash Deferral (North Carolina) (e) Beginning Balance	(f)=(a)x(d) NC Spend	(g) Active Plant COR Offset [2]	(h) Retired Coal Ash Plant COR Offset [2]	(i) Ending Balance	(j)=(e)+((f)+(g)+(h))/2 NC Balance for Return	(k) Deferred Cost of Debt	(l) Compounded annually Deferred Cost of Equity	(m)=(k)+(l) Total Return	(n)=(i)+(m) Total Ending Balance	
1	Aug-17										-					
2	Sep	$ 14,127,429	$ (284,727)	$ (773,130)	60.8102%	$ -	$ 8,590,913	$ (203,721)	$ (642,392)	$ 7,744,801	$ 3,872,400	$ 4,363	$ 17,445	$ 21,808	$ 7,766,608	
3	Oct	13,925,270	(284,727)	(773,130)	60.8102%	7,744,801	8,467,979	(203,721)	(642,392)	15,366,668	11,555,734	13,018	52,059	65,077	15,453,553	
4	Nov	10,319,552	(284,727)	(773,130)	60.8102%	15,366,668	6,275,336	(203,721)	(642,392)	20,795,892	18,081,280	20,370	81,456	101,826	20,984,603	
5	Dec	16,303,059	(284,727)	(773,130)	60.8102%	20,795,892	9,913,917	(203,721)	(642,392)	29,863,696	25,329,794	28,536	114,111	142,647	30,195,054	[4]
6	Jan-18	11,674,153	(284,727)	(773,130)	60.8102%	30,195,054 [4]	7,099,072	(203,721)	(642,392)	36,448,013	33,321,534	45,625	150,114	195,738	36,975,109	
7	Feb	14,436,895	(284,727)	(773,130)	60.8102%	36,448,013	8,779,099	(203,721)	(642,392)	44,381,000	40,414,507	55,336	182,067	237,404	44,618,404	
8	Mar	16,034,812	(142,363)	(386,565)	60.8102%	44,381,000	9,750,795	(101,860)	(321,196)	53,708,740	49,044,870	60,778	210,402	271,181	54,217,324	
9	Apr	12,730,875			60.8452%	53,708,740	7,746,122			61,454,862	57,581,801	71,358	247,026	318,384	62,281,830	
10	May	16,344,206			60.8452%	61,454,862	9,944,659			71,399,521	66,427,191	82,319	284,973	367,292	72,593,781	
11	Jun	13,183,340			60.8452%	71,399,521	8,021,425			79,420,946	75,410,233	93,451	323,510	416,961	81,032,168	
12	Jul	9,840,879			60.8452%	79,420,946	5,987,699			85,408,645	82,414,796	102,132	353,559	455,691	87,475,558	
13	Aug	18,186,966			60.8452%	85,408,645	11,065,890			96,474,535	90,941,590	112,699	390,139	502,838	99,044,286	
14	Sep	14,296,119			60.8452%	96,474,535	8,698,497			105,173,032	100,823,784	124,945	432,534	557,479	108,300,262	
15	Oct	17,794,608			60.8452%	105,173,032	10,827,159			116,000,191	110,586,612	137,044	474,417	611,460	119,738,881	
16	Nov	16,803,192			60.8452%	116,000,191	10,223,930			126,224,122	121,112,156	150,087	519,571	669,658	130,632,470	
17	Dec	25,439,917			60.8452%	126,224,122	15,478,960			141,703,082	133,963,602	166,013	574,704	740,717	147,047,885	[4]
18	Jan-19	20,083,956			60.8452%	147,047,885 [4]	12,220,117			159,268,002	153,157,944	190,629	657,048	847,677	160,115,679	
19	Feb	22,836,296			60.8452%	159,268,002	13,894,782			173,162,784	166,215,393	206,881	713,064	919,945	174,930,406	
20	Mar	24,329,058			60.8452%	173,162,784	14,803,056			187,965,840	180,564,312	224,741	774,621	999,362	190,732,824	
21	Apr	31,140,483			60.8452%	187,965,840	18,947,479			206,913,319	197,439,580	245,745	847,016	1,092,760	210,773,063	
22	May	38,852,313			60.8452%	206,913,319	23,639,754			230,553,073	218,733,196	272,248	938,365	1,210,613	235,623,431	
23	Jun	21,872,397			61.1093%	230,553,073	13,366,073			243,919,146	237,236,110	295,278	1,017,743	1,313,021	250,302,524	
24	Jul	14,696,303			61.1093%	243,919,146	8,980,811			252,899,957	248,409,552	309,185	1,065,677	1,374,862	260,658,197	
25	Aug	72,417,961			61.1093%	252,899,957	44,254,124			297,154,081	275,027,019	342,314	1,179,866	1,522,180	306,434,501	
26	Sep	36,936,002			61.1093%	297,154,081	22,571,340			319,725,421	308,439,751	383,902	1,323,207	1,707,108	330,712,949	
27	Oct	32,420,839			61.1093%	319,725,421	19,812,154			339,537,575	329,631,498	410,278	1,414,119	1,824,397	352,349,501	
28	Nov	32,053,016			61.1093%	339,537,575	19,587,380			359,124,955	349,331,265	434,798	1,498,631	1,933,429	373,870,310	
29	Dec	34,963,720			61.1093%	359,124,955	21,366,091			380,491,047	369,808,001	460,284	1,586,476	2,046,761	397,283,162	[4]
30	Jan-20	13,780,946			61.1093%	397,283,162 [4]	8,421,442			405,704,604	401,493,883	499,722	1,722,409	2,222,131	407,926,735	
31	Feb	26,016,157			61.1093%	405,704,604	15,898,297			421,602,901	413,653,753	514,857	1,774,575	2,289,432	426,114,464	
32	Mar					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	428,447,892	
33	Apr					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	430,781,319	
34	May					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	433,114,747	
35	Jun					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	435,448,174	
36	Jul					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	437,781,602	
37	Aug					421,602,901	-			421,602,901	421,602,901	524,751	1,808,676	2,333,428	440,115,029	
38										-						
39																
40							$ 404,634,354	$ (1,324,184)	$ (4,175,545)			$ 9,207,443	$ 31,772,962	$ 40,980,404	$ 440,115,029	

[1] NC-1103 - Duke Energy Progress - System Spend - Coal Ash
[2] NC 1109 Active and Retired Estimated Cost of Removal / 12
[3] NC-1106 - Allocation Factor - MWHs at Generation Level. Allocation Factors updated when new Cost of Service Factors were available.
[4] Annual compounding formula
[5] NC-1107 - Weighted Cost of Capital Rates for Duke Energy Progress

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1103
Second Settlement

Duke Energy Progress - System Spend - Coal Ash including CAMA - ARO

Line No.	Month	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actual
1	January	$ -	$ 11,674,153	$ 20,083,956	$13,780,946
2	February	-	14,436,895	22,836,296	$26,016,157
3	March	-	16,034,812	24,329,058	
4	April	-	12,730,875	31,140,483	
5	May	-	16,344,206	38,852,313	
6	June	-	13,183,340	21,872,397	
7	July	-	9,840,879	14,696,303	
8	August	-	18,186,966	72,417,961	
9	September	14,127,429	14,296,119	36,936,002	
10	October	13,925,270	17,794,608	32,420,839	
11	November	10,319,552	16,803,192	32,053,016	
12	December	16,303,059	25,439,917	34,963,720	
13		$ 54,675,310	$ 186,765,961	$ 382,602,342	$ 39,797,103

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

		Pre Tax LTD Rate	Pre Tax Equity Rate
Jan - Feb 2018	[5]	2.1479%	7.0670%
Mar - Dec 2018	[5]	1.9440%	6.7297%
2019	[5]	1.9440%	6.7004%
2020	[5]	1.9440%	6.7004%

Duke Energy Progress - Coal Ash Non ARO Retail Return on Plant

Line No.	Month	[1] Total Plant Additions	[2] Accumulated Depreciation	[7] Accumulated Deferred Inc Tax	Net Plant	[3] NC Retail Allocation Factor	NC Retail Net Plant	[4] Balance for Return	Pre Tax Debt Return	Pre Tax Equity Return	Total Return on Investment
		(a)	(b)	(c)	(d)= (a)+(b)+(c)	(e)	(f)	(g)	(h)	(i)	(j)=(h)+(i)
1	Jan-18	$ 37,047	$ -	($3,698)	$ 33,349	60.6008%	$ 20,209	$ 10,105	$ 18	$ 60	$ 78
2	Feb	40,325	(89)	($3,698)	36,539	60.6008%	22,143	21,176	38	125	163
3	Mar	40,473	(206)	($3,698)	36,569	60.6008%	22,161	22,152	36	124	160
4	Apr	48,443	(350)	($3,698)	44,394	61.3372%	27,230	24,696	40	138	179
5	May	5,965,821	(505)	($689,196)	5,276,120	61.3372%	3,236,226	1,631,728	2,643	9,151	11,794
6	Jun	6,050,763	(33,007)	($699,027)	5,318,728	61.3372%	3,262,361	3,249,293	5,264	18,222	23,486
7	Jul	6,104,056	(65,974)	($704,636)	5,333,446	61.3372%	3,271,388	3,266,874	5,292	18,321	23,613
8	Aug	6,204,246	(99,211)	($716,233)	5,388,801	61.3372%	3,305,341	3,288,365	5,327	18,442	23,769
9	Sep	6,275,122	(132,996)	($724,433)	5,417,692	61.3372%	3,323,063	3,314,202	5,369	18,586	23,955
10	Oct	6,302,691	(167,168)	($727,618)	5,407,905	61.3372%	3,317,059	3,320,061	5,378	18,619	23,998
11	Nov	15,144,212	(201,490)	($730,836)	14,211,886	61.3372%	8,717,177	6,017,118	9,748	33,745	43,492
12	Dec	128,515,712	(270,683)	($13,465,465)	114,779,564	61.3372%	70,402,607	39,559,892	64,087	221,856	285,943
13	Jan-19	163,503,908	(579,612)	($13,523,554)	149,400,742	61.3372%	91,638,279	81,020,443	131,253	452,394	583,647
14	Feb	166,667,791	(1,034,819)	($13,705,504)	151,927,469	61.3372%	93,188,103	92,413,191	149,709	516,008	665,717
15	Mar	210,748,372	(1,499,116)	($13,857,568)	195,391,688	61.3372%	119,847,852	106,517,978	172,559	594,765	767,324
16	Apr	347,439,735	(2,062,387)	($26,461,331)	318,916,018	61.3372%	195,614,257	157,731,054	255,524	880,724	1,136,248
17	May	374,337,308	(2,869,578)	($28,891,668)	342,576,062	61.3372%	210,126,673	202,870,465	328,650	1,132,769	1,461,419
18	Jun	377,036,268	(3,721,086)	($29,098,256)	344,216,926	61.5278%	211,789,097	210,957,885	341,752	1,177,927	1,519,678
19	Jul	380,296,416	(4,578,497)	($29,391,796)	346,326,123	61.5278%	213,086,839	212,437,968	344,150	1,186,191	1,530,341
20	Aug	382,363,991	(5,443,126)	($29,566,025)	347,354,840	61.5278%	213,719,786	213,403,313	345,713	1,191,581	1,537,295
21	Sep	383,622,726	(6,311,149)	($29,673,119)	347,638,457	61.5278%	213,894,290	213,807,038	346,367	1,193,836	1,540,203
22	Oct	386,294,290	(7,182,640)	($29,913,455)	349,198,196	61.5278%	214,853,963	214,374,126	347,286	1,197,002	1,544,288
23	Nov	387,918,438	(8,060,320)	($30,058,214)	349,799,904	61.5278%	215,224,181	215,039,072	348,363	1,200,715	1,549,078
24	Dec	387,766,356	(8,941,086)	($30,046,822)	348,778,448	61.5278%	214,595,701	214,909,941	348,154	1,199,994	1,548,148
25	Jan-20	388,617,441	(9,823,223)	($30,124,559)	348,669,658	61.5278%	214,528,765	214,562,233	347,591	1,198,052	1,545,643
26	Feb	389,390,259	(10,706,871)	($30,190,573)	348,492,816	61.5278%	214,419,958	214,474,362	347,448	1,197,562	1,545,010
27	Mar	389,390,259	(11,591,887)	($30,190,573)	347,607,799	61.5278%	213,875,427	214,147,692	346,919	1,195,738	1,542,657
28	Apr	389,390,259	(12,476,903)	($30,190,573)	346,722,783	61.5278%	213,330,896	213,603,161	346,037	1,192,697	1,538,734
29	May	389,390,259	(13,361,919)	($30,190,573)	345,837,767	61.5278%	212,786,365	213,058,630	345,155	1,189,657	1,534,812
30	Jun	389,390,259	(14,246,936)	($30,190,573)	344,952,751	61.5278%	212,241,834	212,514,100	344,273	1,186,616	1,530,889
31	Jul	389,390,259	(15,131,952)	($30,190,573)	344,067,735	61.5278%	211,697,303	211,969,569	343,391	1,183,576	1,526,966
32	Aug	389,390,259	(16,016,968)	($30,190,573)	343,182,719	61.5278%	211,152,772	211,425,038	342,509	1,180,535	1,523,044
											$ 28,131,772

[1] NC-1105 Total Plant in Service beginning on line 61
[2] NC-1105 Total Depreciation Expense beginning on line 95 + Prior Month
[3] NC 1106 Allocation Factor - Demand at Generation Level. Allocation Factors updated when new Cost of Service Factors were available.
[4] Beginning balance + additions for the month/2
[5] NC 1107 Cost of Capital
[6] NC-1105 Total Depreciation Expense beginning on line 99
[7] NC 1110 Accumulated Deferred Income Tax

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - NC Retail Deferral

		After Tax LTD Rate	After Tax Equity Rate
Jan - Feb 2018	[5]	1.6431%	5.4060%
Mar - Dec 2018	[5]	1.4871%	5.1480%
2019	[5]	1.4936%	5.1480%
2020	[5]	1.4936%	5.1480%

Line No.	Month	Beginning Balance (j)=PM(r)	Return on Investment (k)=(i)	[6] Depreciation Expense (l)	[3] NC Retail Allocation Factor (m)	NC Retail Depreciation Expense (n)=(l)*(m)	Balance for Return (o)=(j)+((k)(n))/2	After Tax Debt Return (p)	After Tax Equity Return (q)	Ending Balance (r)
33	Jan-18	$ -	$ 78	$0	60.601%	$0	$ 39	$0	$0	$78
34	Feb	78	163	89	60.601%	54	186	0	1	295
35	Mar	295	160	117	60.601%	71	411	1	2	529
36	Apr	529	179	145	61.337%	89	662	1	3	800
37	May	800	11,794	155	61.337%	95	6,744	8	29	12,726
38	Jun	12,726	23,486	32,503	61.337%	19,936	34,437	43	148	56,339
39	Jul	56,339	23,613	32,967	61.337%	20,221	78,256	97	336	100,605
40	Aug	100,605	23,769	33,237	61.337%	20,387	122,683	152	526	145,439
41	Sep	145,439	23,955	33,785	61.337%	20,723	167,778	208	720	191,045
42	Oct	191,045	23,998	34,172	61.337%	20,960	213,524	265	916	237,183
43	Nov	237,183	43,492	34,322	61.337%	21,052	269,456	334	1,156	303,218
44	Dec	303,218	285,943	69,193	61.337%	42,441	467,410	579	2,005	634,187
45	Jan-19	634,187	583,647	308,929	61.337%	189,488	1,020,755	1,270	4,379	1,412,972
46	Feb	1,412,972	665,717	455,207	61.337%	279,211	1,885,436	2,347	8,089	2,368,336
47	Mar	2,368,336	767,324	464,297	61.337%	284,787	2,894,392	3,603	12,417	3,436,467
48	Apr	3,436,467	1,136,248	563,270	61.337%	345,494	4,177,338	5,199	17,921	4,941,329
49	May	4,941,329	1,461,419	807,192	61.337%	495,109	5,919,593	7,368	25,395	6,930,620
50	Jun	6,930,620	1,519,678	851,507	61.528%	523,914	7,952,417	9,898	34,116	9,018,227
51	Jul	9,018,227	1,530,341	857,412	61.528%	527,547	10,047,170	12,505	43,102	11,131,721
52	Aug	11,131,721	1,537,295	864,629	61.528%	531,987	12,166,362	15,143	52,194	13,268,339
53	Sep	13,268,339	1,540,203	868,023	61.528%	534,076	14,305,479	17,805	61,371	15,421,794
54	Oct	15,421,794	1,544,288	871,491	61.528%	536,209	16,462,043	20,490	70,622	17,593,403
55	Nov	17,593,403	1,549,078	877,680	61.528%	540,017	18,637,951	23,198	79,957	19,785,653
56	Dec	19,785,653	1,548,148	880,766	61.528%	541,916	20,830,685	25,927	89,364	21,991,007
57	Jan-20	21,991,007	1,545,643	882,138	61.528%	542,760	23,035,209	28,671	98,821	24,206,902
58	Feb	24,206,902	1,545,010	883,648	61.528%	543,689	25,251,252	31,429	108,328	26,435,359
59	Mar	26,435,359	1,542,657	885,016	61.528%	544,531	27,478,952	34,202	117,885	28,674,633
60	Apr	28,674,633	1,538,734	885,016	61.528%	544,531	29,716,266	36,987	127,483	30,922,368
61	May	30,922,368	1,534,812	885,016	61.528%	544,531	31,962,039	39,782	137,117	33,178,609
62	Jun	33,178,609	1,530,889	885,016	61.528%	544,531	34,216,319	42,588	146,788	35,443,405
63	Jul	35,443,405	1,526,966	885,016	61.528%	544,531	36,479,153	45,404	156,496	37,716,801
64	Aug	37,716,801	1,523,044	885,016	61.528%	544,531	38,750,589	48,231	166,240	39,998,847
65			$ 28,131,772			$ 9,849,418		$ 453,734	$1,563,924	$ 39,998,847

[1] NC-1105 Total Plant in Service beginning on line 61
[2] NC-1105 Total Depreciation Expense beginning on line 95 + Prior Month
[3] NC 1106 Allocation Factor - Demand at Generation Level. Allocation Factors updated when new Cost of Service Factors were available.
[4] Beginning balance + additions for the month/2
[5] NC 1107 Cost of Capital
[6] NC-1105 Total Depreciation Expense beginning on line 99

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - Monthly Plant in Service

Line No.	Month	D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Monthly Activity
1	Jan-18	$ 600	$ 5,287	$ 33,172									$ 39,059
2	Feb-18	384	3,382										3,766
3	Mar-18	17	152										170
4	Apr-18	933	8,221										9,154
5	May-18	10	86		5,917,295								5,917,390
6	Jun-18	9	83		84,862								84,954
7	Jul-18	571	5,025		48,422								54,017
8	Aug-18	10	86	-	100,106								100,202
9	Sep-18	11	95		70,785								70,890
10	Oct-18	9	82		27,489								27,581
11	Nov-18	(46)	(404)		27,783	7,928,211	885,919						8,841,463
12	Dec-18	63	558	22,853,630	120,532	636,916	71,171	91,254,452	2,736,133				117,673,455
13	Jan-19			35,703,462	14,906	460,572	51,466	96,214	11,224				36,337,843
14	Feb-19			697,284	6,623	875,255	97,803	1,566,335	5,922				3,249,222
15	Mar-19			11,194,568	(108)	(106,205)	(11,868)	1,037,832	19,112	38,659,682			50,793,013
16	Apr-19			942,879		54,876		126,675,492	4,552	306,135	16,184,956	296	144,169,186
17	May-19			350,999		(138,986)		4,047,193	13,597	27,052,817	133,850		31,459,469
18	Jun-19			557,054		21,523		1,672,839	18,087	510,840	101,737		2,882,081
19	Jul-19			562,297		6,167		1,867,243	10,931	681,119	398,571		3,526,327
20	Aug-19			25,456				1,740,230	20,178	395,569	19,888		2,201,320
21	Sep-19			484,528				149,095	63	615,087	159,023		1,407,796
22	Oct-19			512,918				1,239,986	20,479	720,487	429,776		2,923,647
23	Nov-19	(2,572)	2,572	171,688		1,094,491	(1,094,491)	857,166	1,414	799,426	(44,723)		1,784,971
24	Dec-19			513,827				($223,420)	142	(751,628)	236,679		(224,401)
25	Jan-20			55,985				757,550		72,285	9,094		894,914
26	Feb-20			55,077				730,694		19,887			805,658
27	Total	$ -	$ 25,226	$ 74,714,824	$ 6,418,692	$ 10,832,819	$ -	$ 233,468,900	$ 2,861,832	$ 69,081,706	$ 17,628,852	$ 296	$ 415,033,147

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - Total Plant in Service

Line No.	Month	D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Balance Activity
28	Jan-18	$ 600	$ 5,287	$ 33,172	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,059
29	Feb-18	984	8,669	33,172	-	-	-	-	-	-	-	-	42,825
30	Mar-18	1,002	8,821	33,172	-	-	-	-	-	-	-	-	42,995
31	Apr-18	1,935	17,042	33,172	-	-	-	-	-	-	-	-	52,149
32	May-18	1,945	17,128	33,172	5,917,295	-	-	-	-	-	-	-	5,969,539
33	Jun-18	1,954	17,211	33,172	6,002,156	-	-	-	-	-	-	-	6,054,493
34	Jul-18	2,525	22,236	33,172	6,050,579	-	-	-	-	-	-	-	6,108,511
35	Aug-18	2,534	22,322	33,172	6,150,685	-	-	-	-	-	-	-	6,208,713
36	Sep-18	2,545	22,417	33,172	6,221,469	-	-	-	-	-	-	-	6,279,603
37	Oct-18	2,555	22,499	33,172	6,248,958	-	-	-	-	-	-	-	6,307,183
38	Nov-18	2,509	22,095	33,172	6,276,741	7,928,211	885,919	-	-	-	-	-	15,148,647
39	Dec-18	2,572	22,654	22,886,802	6,397,273	8,565,127	957,090	91,254,452	2,736,133	-	-	-	132,822,102
40	Jan-19	2,572	22,654	58,590,264	6,412,178	9,025,699	1,008,555	91,350,665	2,747,357	-	-	-	169,159,945
41	Feb-19	2,572	22,654	59,287,548	6,418,801	9,900,953	1,106,359	92,917,001	2,753,279	-	-	-	172,409,167
42	Mar-19	2,572	22,654	70,482,116	6,418,692	9,794,749	1,094,491	93,954,833	2,772,391	38,659,682	-	-	223,202,180
43	Apr-19	2,572	22,654	71,424,995	6,418,692	9,849,624	1,094,491	220,630,324	2,776,943	38,965,817	16,184,956	296	367,371,365
44	May-19	2,572	22,654	71,775,993	6,418,692	9,710,638	1,094,491	224,677,517	2,790,540	66,018,634	16,318,806	296	398,830,834
45	Jun-19	2,572	22,654	72,333,048	6,418,692	9,732,161	1,094,491	226,350,356	2,808,626	66,529,474	16,420,543	296	401,712,915
46	Jul-19	2,572	22,654	72,895,345	6,418,692	9,738,328	1,094,491	228,217,599	2,819,557	67,210,593	16,819,115	296	405,239,242
47	Aug-19	2,572	22,654	72,920,801	6,418,692	9,738,328	1,094,491	229,957,829	2,839,735	67,606,162	16,839,003	296	407,440,563
48	Sep-19	2,572	22,654	73,405,328	6,418,692	9,738,328	1,094,491	230,106,924	2,839,798	68,221,249	16,998,026	296	408,848,359
49	Oct-19	2,572	22,654	73,918,247	6,418,692	9,738,328	1,094,491	231,346,910	2,860,277	68,941,736	17,427,802	296	411,772,005
50	Nov-19	-	25,226	74,089,934	6,418,692	10,832,819	-	232,204,076	2,861,691	69,741,162	17,383,079	296	413,556,976
51	Dec-19	-	25,226	74,603,762	6,418,692	10,832,819	-	231,980,656	2,861,832	68,989,534	17,619,758	296	413,332,575
52	Jan-20	-	25,226	74,659,747	6,418,692	10,832,819	-	232,738,206	2,861,832	69,061,819	17,628,852	296	414,227,489
53	Feb-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
54	Mar-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
55	Apr-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
56	May-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
57	Jun-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
58	Jul-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	415,033,147
59	Aug-20	-	25,226	74,714,824	6,418,692	10,832,819	-	233,468,900	2,861,832	69,081,706	17,628,852	296	$ 415,033,147

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - Total Plant - Net of JAAR Impact

Line No.	Month	D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Balance Activity
60	JAAR Allocation %	12.94%	12.94%	3.77%				3.77%		16.17%	16.17%		
61	Jan-18	$ 523	$ 4,603	$ 31,921	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,047
62	Feb-18	857	7,547	31,921	-	-	-	-	-	-	-	-	40,325
63	Mar-18	872	7,680	31,921	-	-	-	-	-	-	-	-	40,473
64	Apr-18	1,685	14,837	31,921	-	-	-	-	-	-	-	-	48,443
65	May-18	1,693	14,912	31,921	5,917,295	-	-	-	-	-	-	-	5,965,821
66	Jun-18	1,701	14,984	31,921	6,002,156	-	-	-	-	-	-	-	6,050,763
67	Jul-18	2,198	19,359	31,921	6,050,579	-	-	-	-	-	-	-	6,104,056
68	Aug-18	2,206	19,434	31,921	6,150,685	-	-	-	-	-	-	-	6,204,246
69	Sep-18	2,216	19,516	31,921	6,221,469	-	-	-	-	-	-	-	6,275,122
70	Oct-18	2,224	19,588	31,921	6,248,958	-	-	-	-	-	-	-	6,302,691
71	Nov-18	2,184	19,236	31,921	6,276,741	7,928,211	885,919	-	-	-	-	-	15,144,212
72	Dec-18	2,239	19,723	22,023,970	6,397,273	8,565,127	957,090	87,814,159	2,736,133	-	-	-	128,515,712
73	Jan-19	2,239	19,723	56,381,411	6,412,178	9,025,699	1,008,555	87,906,745	2,747,357	-	-	-	163,503,908
74	Feb-19	2,239	19,723	57,052,408	6,418,801	9,900,953	1,106,359	89,414,030	2,753,279	-	-	-	166,667,791
75	Mar-19	2,239	19,723	67,824,940	6,418,692	9,794,749	1,094,491	90,412,735	2,772,391	32,408,411	-	-	210,748,372
76	Apr-19	2,239	19,723	68,732,273	6,418,692	9,849,624	1,094,491	212,312,561	2,776,943	32,665,044	13,567,849	296	347,439,735
77	May-19	2,239	19,723	69,070,039	6,418,692	9,710,638	1,094,491	216,207,175	2,790,540	55,343,421	13,680,055	296	374,337,308
78	Jun-19	2,239	19,723	69,606,092	6,418,692	9,732,161	1,094,491	217,816,948	2,808,626	55,771,658	13,765,342	296	377,036,268
79	Jul-19	2,239	19,723	70,147,190	6,418,692	9,738,328	1,094,491	219,613,796	2,819,557	56,342,640	14,099,464	296	380,296,416
80	Aug-19	2,239	19,723	70,171,686	6,418,692	9,738,328	1,094,491	221,288,419	2,839,735	56,674,245	14,116,136	296	382,363,991
81	Sep-19	2,239	19,723	70,637,947	6,418,692	9,738,328	1,094,491	221,431,893	2,839,798	57,189,873	14,249,445	296	383,622,726
82	Oct-19	2,239	19,723	71,131,529	6,418,692	9,738,328	1,094,491	222,625,131	2,860,277	57,793,858	14,609,726	296	386,294,290
83	Nov-19	-	21,962	71,296,744	6,418,692	10,832,819	-	223,449,982	2,861,691	58,464,016	14,572,235	296	387,918,438
84	Dec-19	-	21,962	71,791,200	6,418,692	10,832,819	-	223,234,985	2,861,832	57,833,926	14,770,643	296	387,766,356
85	Jan-20	-	21,962	71,845,074	6,418,692	10,832,819	-	223,963,975	2,861,832	57,894,523	14,778,266	296	388,617,441
86	Feb-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
87	Mar-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
88	Apr-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
89	May-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
90	Jun-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
91	Jul-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	389,390,259
92	Aug-20	-	21,962	71,898,075	6,418,692	10,832,819	-	224,667,122	2,861,832	57,911,194	14,778,266	296	$ 389,390,259

Source: Duke Energy Asset Accounting

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

Duke Energy Progress - Coal Ash Non ARO - System Depreciation Expense (Net of JAAR)

		D FOS 315 ROXBORO #4-50121	D FOS 312 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 311 MAYO #1-50121	D FOS 312 MAYO #1-50121	D FOS 312 ROXBORO #2-50121	Total Balance Activity
93	Depr Rate Prior To 3/16/2018	0.45%	0.45%	3.26%									
94	Depr Rate Beg. 3/16/2018	3.05%	1.33%	5.03%	6.56%	4.74%	4.61%	1.91%	1.90%	1.95%	4.02%	5.04%	
95	Jan-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Feb-18	0	2	87	-	-	-	-	-	-	-	-	89
97	Mar-18	1	6	110	-	-	-	-	-	-	-	-	117
98	Apr-18	2	9	134	-	-	-	-	-	-	-	-	145
99	May-18	4	16	134	-	-	-	-	-	-	-	-	155
100	Jun-18	4	17	134	32,348	-	-	-	-	-	-	-	32,503
101	Jul-18	4	17	134	32,812	-	-	-	-	-	-	-	32,967
102	Aug-18	6	21	134	33,076	-	-	-	-	-	-	-	33,237
103	Sep-18	6	22	134	33,624	-	-	-	-	-	-	-	33,785
104	Oct-18	6	22	134	34,011	-	-	-	-	-	-	-	34,172
105	Nov-18	6	22	134	34,161	-	-	-	-	-	-	-	34,322
106	Dec-18	6	21	134	34,313	31,316	3,403	-	-	-	-	-	69,193
107	Jan-19	6	22	92,317	34,972	33,832	3,677	139,771	4,332	-	-	-	308,929
108	Feb-19	6	22	236,332	35,053	35,652	3,875	139,918	4,350	-	-	-	455,207
109	Mar-19	6	22	239,145	35,089	39,109	4,250	142,317	4,359	-	-	-	464,297
110	Apr-19	6	22	284,300	35,089	38,689	4,205	143,907	4,390	52,664	-	-	563,270
111	May-19	6	22	288,103	35,089	38,906	4,205	337,931	4,397	53,081	45,452	1	807,192
112	Jun-19	6	22	289,519	35,089	38,357	4,205	344,130	4,418	89,933	45,828	1	851,507
113	Jul-19	6	22	291,766	35,089	38,442	4,205	346,692	4,447	90,629	46,114	1	857,412
114	Aug-19	6	22	294,034	35,089	38,466	4,205	349,552	4,464	91,557	47,233	1	864,629
115	Sep-19	6	22	294,136	35,089	38,466	4,205	352,217	4,496	92,096	47,289	1	868,023
116	Oct-19	6	22	296,091	35,089	38,466	4,205	352,446	4,496	92,934	47,736	1	871,491
117	Nov-19	6	22	298,160	35,089	38,466	4,205	354,345	4,529	93,915	48,943	1	877,680
118	Dec-19	-	24	298,852	35,089	42,790	-	355,658	4,531	95,004	48,817	1	880,766
119	Jan-20	-	24	300,925	35,089	42,790	-	355,316	4,531	93,980	49,482	1	882,138
120	Feb-20	-	24	301,151	35,089	42,790	-	356,476	4,531	94,079	49,507	1	883,648
121	Mar-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
122	Apr-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
123	May-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
124	Jun-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
125	Jul-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	885,016
126	Aug-20	-	24	301,373	35,089	42,790	-	357,595	4,531	94,106	49,507	1	$ 885,016

Source: Duke Energy Asset Accounting

Depreciation Expense = Prior month Total Plant Net of JAAR * Depreciation Rate /12

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1106
Second Settlement

Duke Energy Progress - Cost of Service - Allocation Factors

Line No.	Allocation Factor	NC Retail 2016	NC Retail 2017	NC Retail 2018
1	Allocation Factor - DPAll Demand at Generation Level	60.6008%	61.3372%	61.5278%
2	Allocation Factor - Energy @ Prod. Output MWHs at Generation	60.8102%	60.8452%	61.1093%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1107
Second Settlement

Cost of debt and Equity for coal ash deferral periods

Sep 2017 - Dec 2017

	Capitalization Ratio [1]	Approved Cost Rate [1]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	47.00%	4.57%	2.1479%	1.3519%	2.1479%	
EQUITY	53.00%	10.20%	5.4060%	5.4060%	7.0670%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.5539%	6.7579%	9.2149%	

Return on Equity	2.188%	
Effective State and Federal Income Tax Rate	37.06%	(e)

Jan-Feb 2018

	Capitalization Ratio [1]	Approved Cost Rate [1]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	47.00%	4.57%	2.1479%	1.6431%	2.1479%	
EQUITY	53.00%	10.20%	5.4060%	5.4060%	7.0670%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.5539%	7.0491%	9.2149%	

Return on Equity	2.479%	
Effective State and Federal Income Tax Rate	23.50%	[3]

Mar - Dec 2018

	Capitalization Ratio [2]	Approved Cost Rate [2]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	48.00%	4.05%	1.9440%	1.4871%	1.9440%	
EQUITY	52.00%	9.90%	5.1480%	5.1480%	6.7297%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.0920%	6.6351%	8.6737%	

Return on Equity	2.585%	
Effective State and Federal Income Tax Rate	23.50%	[3]

2019

	Capitalization Ratio [2]	Approved Cost Rate [2]	WEIGHTED COST OF CAPITAL RETURN	AFTER TAX	BEFORE TAX	
	(a)	(b)	(c) = (a) x (b)	(d)		
LONG TERM DEBT	48.00%	4.05%	1.9440%	1.4936%	1.9440%	
EQUITY	52.00%	9.90%	5.1480%	5.1480%	6.7004%	(f) = (d)/((a)-(e))
TOTAL	100.00%		7.0920%	6.6416%	8.6444%	

Return on Equity	2.592%	
Effective State and Federal Income Tax Rate	23.17%	[4]

[1] Cost of capital rates from Docket No. E-2, Sub 1023
[2] Cost of capital rates from Docket No. E-2, Sub 1142
[3] Duke Energy Accounting
[4] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC-1108
Second Settlement

Depreciation Rates

Line No.	Depreciation Rate	Prior to Mar 16 2018	Beg. Mar 16 2018 {1}
1	D FOS 315 ROXBORO #4	0.45%	3.05%
2	D FOS 311 ROXBORO COMMON	3.26%	5.03%
3	D FOS 312 ROXBORO #3-50121		4.74%
4	D FOS 312 ROXBORO #4	0.45%	1.33%
5	D FOS 312 ROXBORO #1		6.56%
6	D FOS 315 ROXBORO #3-50121		4.61%
7	D FOS 312 ROXBORO COMMON-50121		1.91%
8	D FOS 312 ROXBORO #2-50121		5.04%
9	D FOS 311 MAYO #1-50121		1.95%
10	D FOS 312 MAYO #1-50121		4.02%
11	D TRN 353-BU-Transmission 50126		1.90%

Source: Duke Energy Asset Accounting

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018
(Dollars in thousands)

NC 1109
Second Settlement

Estimate of Cost of Removal for Closure of Ash Ponds

Line		Decommissioning Amount for Closure of Ash Ponds [1]											
1		(a)	(b)	(c)	(d)	(e)	(f)	(g)		(h) = [3] x (d)/(g)	(k)=[3] x (d)/(g)	(j)=[3] x (d)/(g)	(k) x (j)
2	Plant	Closure of Ash Ponds [2]	Project Indirects Adder (5%) [2]	Contingency (10%) [2]	Total	Est. Retirement Date per Depr Study	Depr Study Implementation Date	Retail Recovery Period (in years) [4]	Wholesale Recovery Period (in years) [5]	Annual Retail COR for Ash Pond Closure	NC Annual Retail COR	Wholesale/ Remaining Annual COR	Annual COR for Closure of Ash Ponds
3													
4	Cape Fear	$ 22,000	$ 1,100	$ 2,200	$ 25,300		July 1, 2012	10	13	$ 1,882	$ 1,631	$ 505	$ 2,136
5	Lee	43,000	2,150	4,300	49,450		July 1, 2012	10	27	3,678	3,187	464	3,651
6	Robinson	11,000	550	1,100	12,650		July 1, 2012	10	27	941	815	120	935
7	Sutton	21,000	1,050	2,100	24,150		July 1, 2012	10	16	1,796	1,557	395	1,952
8	Weatherspoon	7,000	350	700	8,050		July 1, 2012	10	24	599	519	85	604
9	Subtotal Early-Retired Plants	104,000	5,200	10,400	119,600					8,895	7,709	1,569	9,278
10	Asheville	9,000	450	900	10,350	2033	July 1, 2012	21	21	367	318	126	444
11	Mayo	19,000	950	1,900	21,850	2035	July 1, 2012	23	23	707	612	243	856
12	Roxboro	47,000	2,350	4,700	54,050	2035	July 1, 2012	23	23	1,748	1,515	602	2,117
13	Subtotal active plants	75,000	3,750	7,500	86,250					2,821	2,445	972	3,417
14	Total	$ 179,000	$ 8,950	$ 17,900	$ 205,850					$ 11,716	$ 10,153	$ 2,541	$ 12,694

[1] Amounts reflect 100% system amounts.
[2] Amounts per DEP Dismantlement Study
[3] Based on allocation factors from the 2012 NC rate case

COR for Ash Pond Closure	74.371%
NC Retail	64.454%
Wholesale	25.629%

[4] Remaining Life per Depreciation Study
[5] Remaining Life per FERC Settlement Agreement

I/A

Smith Second Settlement Exhibit 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1110
Second Settlement

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description																		
Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
201801								5287.06	600.28								33171.55	39,059
201802								3,382	384									3,766
201803								152	17									170
201804								8,221	933									9,154
201805				5,917,295				86	10									5,917,390
201806				84,862				83	9									84,954
201807				48,422				5,025	571									54,017
201808				100,106				86	10								-	100,202
201809				70,785				95	11									70,890
201810				27,489				82	9									27,581
201811				27,783		7,928,211	885,919	(404)	(46)									8,841,463
201812		2,736,133	91,254,452	120,532		636,916	71,171	558	63							22,853,630		117,673,455
201901		11,224	96,214	14,906		460,572	51,466								35,294,091	409,371		36,337,843
201902		5,922	1,566,335	6,623		875,255	97,803								638,355	58,929		3,249,222
201903		19,112	1,037,832	(108)		(106,205)	(11,868)			6,700,621			38,659,682		4,167,608	326,339		50,793,013
201904		4,552	1,602,076		296	54,876				198,486	16,184,956		306,135	125,073,416	625,589	118,804		144,169,186
201905		13,597	690,918			(138,986)				157,701	133,850	26,796,814	256,002	3,356,275	536,750	(343,452)		31,459,469
201906		18,087	(225,274)			21,523				175,967	101,737	429,079	81,761	1,898,113	191,077	190,010		2,882,081
201907		10,931	101,010			6,167				30,652	398,571	590,493	90,626	1,766,232	101,796	429,849		3,526,327
201908		20,178	432,993							28,874	19,888	206,809	188,760	1,307,237	70,465	(73,883)		2,201,320
201909	(318,728)	63								(14,927)	159,023	451,967	163,120	467,823	20,131	479,324		1,407,796
201910	109,744	20,479								48,993	429,776	742,253	(21,766)	1,130,242	138,786	325,140		2,923,647
201911		1,414	14,208			1,094,491	(1,094,491)	2,572	(2,572)	78,554	(44,723)	789,320	10,105	842,958	2,096	91,039		1,784,971
201912		142	(17,606)							31,962	236,679	(781,554)	29,926	(205,814)	22,064	459,801		(224,401)
202001			(92)							9,076	9,094	72,150	135	757,642	12,230	34,679		894,914
202002										18,111		19,887		730,694	43,218	(6,252)		805,658
Grand Total	(208,984)	2,861,832	96,553,065	6,418,692	296	10,832,819	-	25,226	-	7,464,069	17,628,852	29,317,218	39,764,487	137,124,819	41,864,255	25,353,328	33,172	415,033,147

Cumulative Plant additions

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description																		
Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU-Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1-50121	D FOS 312 ROXBORO #2-50121	D FOS 312 ROXBORO #3-50121	D FOS 315 ROXBORO #3-50121	D FOS 312 ROXBORO #4-50121	D FOS 315 ROXBORO #4-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
201801	-	-	-	-	-	-	-	5,287	600	-	-	-	-	-	-	-	33,172	39,059
201802	-	-	-	-	-	-	-	8,669	984	-	-	-	-	-	-	-	33,172	42,825
201803	-	-	-	-	-	-	-	8,821	1,002	-	-	-	-	-	-	-	33,172	42,995
201804	-	-	-	-	-	-	-	17,042	1,935	-	-	-	-	-	-	-	33,172	52,149
201805	-	-	-	5,917,295	-	-	-	17,128	1,945	-	-	-	-	-	-	-	33,172	5,969,539
201806	-	-	-	6,002,156	-	-	-	17,211	1,954	-	-	-	-	-	-	-	33,172	6,054,493
201807	-	-	-	6,050,579	-	-	-	22,236	2,525	-	-	-	-	-	-	-	33,172	6,108,511
201808	-	-	-	6,150,685	-	-	-	22,322	2,534	-	-	-	-	-	-	-	33,172	6,208,713
201809	-	-	-	6,221,469	-	-	-	22,417	2,545	-	-	-	-	-	-	-	33,172	6,279,603
201810	-	-	-	6,248,958	-	-	-	22,499	2,555	-	-	-	-	-	-	-	33,172	6,307,183
201811	-	-	-	6,276,741	-	7,928,211	885,919	22,095	2,509	-	-	-	-	-	-	-	33,172	15,148,647
201812	-	2,736,133	91,254,452	6,397,273	-	8,565,127	957,090	22,654	2,572	-	-	-	-	-	-	22,853,630	33,172	132,822,102
201901	-	2,747,357	91,350,665	6,412,178	-	9,025,699	1,008,555	22,654	2,572	-	-	-	-	-	35,294,091	23,263,001	33,172	169,159,945
201902	-	2,753,279	92,917,001	6,418,801	-	9,900,953	1,106,359	22,654	2,572	-	-	-	-	-	35,932,446	23,321,930	33,172	172,409,167
201903	-	2,772,391	93,954,833	6,418,692	-	9,794,749	1,094,491	22,654	2,572	6,700,621	-	-	38,659,682	-	40,100,055	23,648,269	33,172	223,202,180
201904	-	2,776,943	95,556,908	6,418,692	296	9,849,624	1,094,491	22,654	2,572	6,899,107	16,184,956	-	38,965,817	125,073,416	40,725,643	23,767,073	33,172	367,371,365
201905	-	2,790,540	96,247,826	6,418,692	296	9,710,638	1,094,491	22,654	2,572	7,056,807	16,318,806	26,796,814	39,221,819	128,429,691	41,262,394	23,423,621	33,172	398,830,834
201906	-	2,808,626	96,022,552	6,418,692	296	9,732,161	1,094,491	22,654	2,572	7,232,775	16,420,543	27,225,893	39,303,580	130,327,804	41,453,471	23,613,631	33,172	401,712,915
201907	-	2,819,557	96,123,562	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,263,427	16,819,115	27,816,387	39,394,206	132,094,037	41,555,267	24,043,479	33,172	405,239,242
201908	-	2,839,735	96,556,555	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,292,301	16,839,003	28,023,196	39,582,966	133,401,274	41,625,731	23,969,597	33,172	407,440,563
201909	(318,728)	2,839,798	96,556,555	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,277,373	16,998,026	28,475,163	39,746,086	133,869,097	41,645,862	24,448,921	33,172	408,848,359
201910	(208,984)	2,860,277	96,556,555	6,418,692	296	9,738,328	1,094,491	22,654	2,572	7,326,367	17,427,802	29,217,416	39,724,321	134,999,339	41,784,648	24,774,061	33,172	411,772,005
201911	(208,984)	2,861,691	96,570,763	6,418,692	296	10,832,819	-	25,226	-	7,404,920	17,383,079	30,006,736	39,734,426	135,842,298	41,786,744	24,865,099	33,172	413,556,976
201912	(208,984)	2,861,832	96,553,157	6,418,692	296	10,832,819	-	25,226	-	7,436,882	17,619,758	29,225,182	39,764,352	135,636,484	41,808,807	25,324,901	33,172	413,332,575
202001	(208,984)	2,861,832	96,553,065	6,418,692	296	10,832,819	-	25,226	-	7,445,958	17,628,852	29,297,331	39,764,487	136,394,125	41,821,037	25,359,580	33,172	414,227,489
202002	(208,984)	2,861,832	96,553,065	6,418,692	296	10,832,819	-	25,226	-	7,464,069	17,628,852	29,317,218	39,764,487	137,124,819	41,864,255	25,353,328	33,172	415,033,147

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1110
Second Settlement

Total Plant - Net of JAAR Impact

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description																		
Depreciation Group	**D FOS 312 ROXBORO COMMON-50121**	**D TRN 353-BU-Transmission 50126**	**D FOS 312 ROXBORO COMMON-50121**	**D FOS 312 ROXBORO #1-50121**	**D FOS 312 ROXBORO #2-50121**	**D FOS 312 ROXBORO #3-50121**	**D FOS 315 ROXBORO #3-50121**	**D FOS 312 ROXBORO #4-50121**	**D FOS 315 ROXBORO #4-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 312 MAYO #1-50121**	**D FOS 311 MAYO #1-50121**	**D FOS 311 MAYO #1-50121**	**D FOS 312 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	
JAAR %	**3.77%**		**3.77%**					**12.94%**	**12.94%**	**3.77%**	**16.17%**	**16.17%**	**16.17%**	**3.77%**	**3.77%**	**3.77%**	**3.77%**	
201801	-	-	-	-	-	-	-	4,603	523	-	-	-	-	-	-	-	31,921	37,047
201802	-	-	-	-	-	-	-	7,547	857	-	-	-	-	-	-	-	31,921	40,325
201803	-	-	-	-	-	-	-	7,680	872	-	-	-	-	-	-	-	31,921	40,473
201804	-	-	-	-	-	-	-	14,837	1,685	-	-	-	-	-	-	-	31,921	48,443
201805	-	-	-	5,917,295	-	-	-	14,912	1,693	-	-	-	-	-	-	-	31,921	5,965,821
201806	-	-	-	6,002,156	-	-	-	14,984	1,701	-	-	-	-	-	-	-	31,921	6,050,763
201807	-	-	-	6,050,579	-	-	-	19,359	2,198	-	-	-	-	-	-	-	31,921	6,104,056
201808	-	-	-	6,150,685	-	-	-	19,434	2,206	-	-	-	-	-	-	-	31,921	6,204,246
201809	-	-	-	6,221,469	-	-	-	19,516	2,216	-	-	-	-	-	-	-	31,921	6,275,122
201810	-	-	-	6,248,958	-	-	-	19,588	2,224	-	-	-	-	-	-	-	31,921	6,302,691
201811	-	-	-	6,276,741	-	7,928,211	885,919	19,236	2,184	-	-	-	-	-	-	-	31,921	15,144,212
201812	-	2,736,133	87,814,159	6,397,273	-	8,565,127	957,090	19,723	2,239	-	-	-	-	-	-	21,992,049	31,921	128,515,712
201901	-	2,747,357	87,906,745	6,412,178	-	9,025,699	1,008,555	19,723	2,239	-	-	-	-	-	33,963,504	22,385,986	31,921	163,503,908
201902	-	2,753,279	89,414,030	6,418,801	-	9,900,953	1,106,359	19,723	2,239	-	-	-	-	-	34,577,793	22,442,694	31,921	166,667,791
201903	-	2,772,391	90,412,735	6,418,692	-	9,794,749	1,094,491	19,723	2,239	6,448,007	-	-	32,408,411	-	38,588,283	22,756,729	31,921	210,748,372
201904	-	2,776,943	91,954,413	6,418,692	296	9,849,624	1,094,491	19,723	2,239	6,639,010	13,567,849	-	32,665,044	120,358,148	39,190,287	22,871,055	31,921	347,439,735
201905	-	2,790,540	92,619,283	6,418,692	296	9,710,638	1,094,491	19,723	2,239	6,790,766	13,680,055	22,463,770	32,879,651	123,587,892	39,706,801	22,540,550	31,921	374,337,308
201906	-	2,808,626	92,402,502	6,418,692	296	9,732,161	1,094,491	19,723	2,239	6,960,099	13,765,342	22,823,466	32,948,191	125,414,446	39,890,675	22,723,397	31,921	377,036,268
201907	-	2,819,557	92,499,704	6,418,692	296	9,738,328	1,094,491	19,723	2,239	6,989,596	14,099,464	23,318,477	33,024,163	127,114,092	39,988,633	23,137,040	31,921	380,296,416
201908	-	2,839,735	92,916,373	6,418,692	296	9,738,328	1,094,491	19,723	2,239	7,017,381	14,116,136	23,491,845	33,182,400	128,372,046	40,056,441	23,065,943	31,921	382,363,991
201909	(306,712)	2,839,798	92,916,373	6,418,692	296	9,738,328	1,094,491	19,723	2,239	7,003,016	14,249,445	23,870,729	33,319,144	128,822,232	40,075,813	23,527,197	31,921	383,622,726
201910	(201,106)	2,860,277	92,916,373	6,418,692	296	9,738,328	1,094,491	19,723	2,239	7,050,163	14,609,726	24,492,960	33,300,898	129,909,864	40,209,367	23,840,078	31,921	386,294,290
201911	(201,106)	2,861,691	92,930,045	6,418,692	296	10,832,819	-	21,962	-	7,125,755	14,572,235	25,154,647	33,309,369	130,721,043	40,211,383	23,927,685	31,921	387,918,438
201912	(201,106)	2,861,832	92,913,103	6,418,692	296	10,832,819	-	21,962	-	7,156,512	14,770,643	24,499,470	33,334,457	130,522,988	40,232,615	24,370,152	31,921	387,766,356
202001	(201,106)	2,861,832	92,913,014	6,418,692	296	10,832,819	-	21,962	-	7,165,245	14,778,266	24,559,953	33,334,570	131,252,067	40,244,384	24,403,524	31,921	388,617,441
202002	(201,106)	2,861,832	92,913,014	6,418,692	296	10,832,819	-	21,962	-	7,182,674	14,778,266	24,576,624	33,334,570	131,955,214	40,285,973	24,397,507	31,921	389,390,259

Depreciation Expense

Project	20087848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description	**D FOS 312 ROXBORO COMMON-50121**	**D TRN 353-BU-Transmission 50126**	**D FOS 312 ROXBORO COMMON-50121**	**D FOS 312 ROXBORO #1-50121**	**D FOS 312 ROXBORO #2-50121**	**D FOS 312 ROXBORO #3-50121**	**D FOS 315 ROXBORO #3-50121**	**D FOS 312 ROXBORO #4-50121**	**D FOS 315 ROXBORO #4-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 312 MAYO #1-50121**	**D FOS 311 MAYO #1-50121**	**D FOS 311 MAYO #1-50121**	**D FOS 312 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	
Depreciation Group	**D FOS 312 ROXBORO COMMON-50121**	**D TRN 353-BU-Transmission 50126**	**D FOS 312 ROXBORO COMMON-50121**	**D FOS 312 ROXBORO #1-50121**	**D FOS 312 ROXBORO #2-50121**	**D FOS 312 ROXBORO #3-50121**	**D FOS 315 ROXBORO #3-50121**	**D FOS 312 ROXBORO #4-50121**	**D FOS 315 ROXBORO #4-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 312 MAYO #1-50121**	**D FOS 311 MAYO #1-50121**	**D FOS 311 MAYO #1-50121**	**D FOS 312 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	**D FOS 311 ROXBORO COMMON-50121**	
Depr Rate Prior To 3/16/2018								0.45%	0.45%	3.26%					3.26%	3.26%	3.26%	
Depr Rate Beg. 3/16/2018	1.91%	1.90%	1.91%	6.56%	5.04%	4.74%	4.61%	1.33%	3.05%	5.03%	4.02%	1.95%	1.95%	1.91%	5.03%	5.03%	5.03%	
201801																		
201802	-	-	-	-	-	-	-	2	0	-	-	-	-	-	-	-	87	89
201803	-	-	-	-	-	-	-	6	1	-	-	-	-	-	-	-	110	117
201804	-	-	-	-	-	-	-	9	2	-	-	-	-	-	-	-	134	145
201805	-	-	-	-	-	-	-	16	4	-	-	-	-	-	-	-	134	155
201806	-	-	-	32,348	-	-	-	17	4	-	-	-	-	-	-	-	134	32,503
201807	-	-	-	32,812	-	-	-	17	4	-	-	-	-	-	-	-	134	32,967
201808	-	-	-	33,077	-	-	-	21	6	-	-	-	-	-	-	-	134	33,237
201809	-	-	-	33,624	-	-	-	22	6	-	-	-	-	-	-	-	134	33,785
201810	-	-	-	34,011	-	-	-	22	6	-	-	-	-	-	-	-	134	34,172
201811	-	-	-	34,161	-	-	-	22	6	-	-	-	-	-	-	-	134	34,322
201812	-	-	-	34,313	-	31,316	3,403	21	6	-	-	-	-	-	-	-	134	69,193
201901	-	4,332	139,771	34,972	-	33,832	3,677	22	6	-	-	-	-	-	-	92,183	134	308,929
201902	-	4,350	139,918	35,053	-	35,652	3,875	22	6	-	-	-	-	-	142,364	93,835	134	455,207
201903	-	4,359	142,317	35,089	-	39,109	4,250	22	6	-	-	-	-	-	144,939	94,072	134	464,297
201904	-	4,390	143,907	35,089	-	38,689	4,205	22	6	27,028	-	-	52,664	-	161,749	95,389	134	563,270
201905	-	4,397	146,361	35,089	1	38,906	4,205	22	6	27,829	45,452	-	53,081	191,570	164,273	95,868	134	807,192
201906	-	4,418	147,419	35,089	1	38,357	4,205	22	6	28,465	45,828	36,504	53,429	196,711	166,438	94,482	134	851,507
201907	-	4,447	147,074	35,089	1	38,442	4,205	22	6	29,174	46,114	37,088	53,541	199,618	167,208	95,249	134	857,412
201908	-	4,464	147,229	35,089	1	38,466	4,205	22	6	29,298	47,233	37,893	53,664	202,323	167,619	96,983	134	864,629
201909	-	4,496	147,892	35,089	1	38,466	4,205	22	6	29,415	47,289	38,174	53,921	204,326	167,903	96,685	134	868,023
201910	(488)	4,496	147,892	35,089	1	38,466	4,205	22	6	29,354	47,736	38,790	54,144	205,042	167,984	98,618	134	871,491
201911	(320)	4,529	147,892	35,089	1	38,466	4,205	22	6	29,552	48,943	39,801	54,114	206,773	168,544	99,930	134	877,680
201912	(320)	4,531	147,914	35,089	1	42,790	-	24	-	29,869	48,817	40,876	54,128	208,064	168,553	100,297	134	880,766
202001	(320)	4,531	147,887	35,089	1	42,790	-	24	-	29,998	49,482	39,812	54,168	207,749	168,642	102,152	134	882,138
202002	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,034	49,507	39,910	54,169	208,910	168,691	102,291	134	883,648
202003	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202004	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202005	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202006	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202007	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
202008	(320)	4,531	147,887	35,089	1	42,790	-	24	-	30,107	49,507	39,937	54,169	210,029	168,865	102,266	134	885,016
																		-

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1110
Second Settlement

Accumulated Depreciation

Project	20087848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU- Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1- 50121	D FOS 312 ROXBORO #2- 50121	D FOS 312 ROXBORO #3- 50121	D FOS 315 ROXBORO #3- 50121	D FOS 312 ROXBORO #4- 50121	D FOS 315 ROXBORO #4- 50121	D FOS 311 ROXBORO COMMON-50121	MAYO #1-50121	MAYO #1-50121	MAYO #1-50121	COMMON-50121	COMMON-50121	COMMON-50121	COMMON-50121	
Depreciation Group	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU- Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1- 50121	D FOS 312 ROXBORO #2- 50121	D FOS 312 ROXBORO #3- 50121	D FOS 315 ROXBORO #3- 50121	D FOS 312 ROXBORO #4- 50121	D FOS 315 ROXBORO #4- 50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
201802	-	-	-	-	-	-	-	(2)	(0)	-	-	-	-	-	-	-	(87)	(89)
201803	-	-	-	-	-	-	-	(7)	(1)	-	-	-	-	-	-	-	(197)	(206)
201804	-	-	-	-	-	-	-	(16)	(4)	-	-	-	-	-	-	-	(331)	(350)
201805	-	-	-	-	-	-	-	(32)	(8)	-	-	-	-	-	-	-	(465)	(505)
201806	-	-	-	(32,348)	-	-	-	(49)	(12)	-	-	-	-	-	-	-	(599)	(33,007)
201807	-	-	-	(65,160)	-	-	-	(65)	(17)	-	-	-	-	-	-	-	(732)	(65,974)
201808	-	-	-	(98,236)	-	-	-	(87)	(22)	-	-	-	-	-	-	-	(866)	(99,211)
201809	-	-	-	(131,860)	-	-	-	(108)	(28)	-	-	-	-	-	-	-	(1,000)	(132,996)
201810	-	-	-	(165,871)	-	-	-	(130)	(33)	-	-	-	-	-	-	-	(1,134)	(167,168)
201811	-	-	-	(200,032)	-	-	-	(152)	(39)	-	-	-	-	-	-	-	(1,268)	(201,490)
201812	-	-	-	(234,344)	-	(31,316)	(3,403)	(173)	(45)	-	-	-	-	-	-	-	(1,401)	(270,683)
201901	-	(4,332)	(139,771)	(269,316)	-	(65,149)	(7,080)	(195)	(50)	-	-	-	-	-	-	(92,183)	(1,535)	(579,612)
201902	-	(8,682)	(279,689)	(304,369)	-	(100,800)	(10,955)	(217)	(56)	-	-	-	-	-	(142,364)	(186,018)	(1,669)	(1,034,819)
201903	-	(13,042)	(422,006)	(339,459)	-	(139,909)	(15,205)	(239)	(62)	-	-	-	-	-	(287,302)	(280,090)	(1,803)	(1,499,116)
201904	-	(17,431)	(565,913)	(374,548)	-	(178,598)	(19,410)	(261)	(67)	(27,028)	-	-	(52,664)	-	(449,051)	(375,479)	(1,937)	(2,062,386)
201905	-	(21,828)	(712,274)	(409,637)	(1)	(217,504)	(23,614)	(282)	(73)	(54,856)	(45,452)	-	(105,744)	(191,570)	(613,324)	(471,347)	(2,070)	(2,869,578)
201906	-	(26,246)	(859,693)	(444,725)	(3)	(255,861)	(27,819)	(304)	(79)	(83,321)	(91,280)	(36,504)	(159,174)	(388,281)	(779,762)	(565,829)	(2,204)	(3,721,086)
201907	-	(30,693)	(1,006,767)	(479,814)	(4)	(294,303)	(32,024)	(326)	(84)	(112,495)	(137,394)	(73,592)	(212,715)	(587,899)	(946,970)	(661,078)	(2,338)	(4,578,497)
201908	-	(35,158)	(1,153,996)	(514,903)	(5)	(332,770)	(36,228)	(348)	(90)	(141,794)	(184,628)	(111,484)	(266,379)	(790,222)	(1,114,589)	(758,061)	(2,472)	(5,443,126)
201909	-	(39,654)	(1,301,888)	(549,992)	(6)	(371,236)	(40,433)	(370)	(96)	(171,208)	(231,917)	(149,659)	(320,300)	(994,548)	(1,282,492)	(854,746)	(2,606)	(6,311,149)
201910	488	(44,150)	(1,449,780)	(585,081)	(8)	(409,703)	(44,638)	(392)	(102)	(200,562)	(279,652)	(188,448)	(374,444)	(1,199,590)	(1,450,477)	(953,364)	(2,739)	(7,182,640)
201911	808	(48,679)	(1,597,672)	(620,170)	(9)	(448,169)	(48,842)	(414)	(107)	(230,114)	(328,595)	(228,250)	(428,558)	(1,406,363)	(1,619,021)	(1,053,293)	(2,873)	(8,060,320)
201912	1,128	(53,210)	(1,745,585)	(655,259)	(10)	(490,959)	(48,842)	(438)	(107)	(259,983)	(377,412)	(269,126)	(482,686)	(1,614,427)	(1,787,574)	(1,153,590)	(3,007)	(8,941,086)
202001	1,448	(57,741)	(1,893,472)	(690,347)	(11)	(533,748)	(48,842)	(462)	(107)	(289,981)	(426,893)	(308,937)	(536,854)	(1,822,176)	(1,956,216)	(1,255,742)	(3,141)	(9,823,223)
202002	1,769	(62,272)	(2,041,358)	(725,436)	(13)	(576,538)	(48,842)	(487)	(107)	(320,015)	(476,401)	(348,847)	(591,023)	(2,031,086)	(2,124,907)	(1,358,033)	(3,275)	(10,706,871)
202003	2,089	(66,804)	(2,189,245)	(760,525)	(14)	(619,327)	(48,842)	(511)	(107)	(350,122)	(525,908)	(388,784)	(645,191)	(2,241,114)	(2,293,772)	(1,460,299)	(3,408)	(11,591,887)
202004	2,409	(71,335)	(2,337,132)	(795,614)	(15)	(662,117)	(48,842)	(535)	(107)	(380,230)	(575,415)	(428,721)	(699,360)	(2,451,143)	(2,462,637)	(1,562,566)	(3,542)	(12,476,903)
202005	2,729	(75,866)	(2,485,018)	(830,703)	(16)	(704,907)	(48,842)	(560)	(107)	(410,337)	(624,922)	(468,658)	(753,529)	(2,661,172)	(2,631,503)	(1,664,832)	(3,676)	(13,361,919)
202006	3,049	(80,397)	(2,632,905)	(865,792)	(18)	(747,696)	(48,842)	(584)	(107)	(440,445)	(674,429)	(508,595)	(807,697)	(2,871,201)	(2,800,368)	(1,767,098)	(3,810)	(14,246,936)
202007	3,369	(84,929)	(2,780,791)	(900,880)	(19)	(790,486)	(48,842)	(608)	(107)	(470,552)	(723,937)	(548,532)	(861,866)	(3,081,229)	(2,969,234)	(1,869,364)	(3,944)	(15,131,952)
202008	3,689	(89,460)	(2,928,678)	(935,969)	(20)	(833,276)	(48,842)	(633)	(107)	(500,659)	(773,444)	(588,469)	(916,035)	(3,291,258)	(3,138,099)	(1,971,631)	(4,077)	(16,016,968)

Tax Basis for Bonus Depreciation ADIT

Project	20087848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description	D FOS 312 ROXBORO COMMON-50121	D TRN 353-BU- Transmission 50126	D FOS 312 ROXBORO COMMON-50121	D FOS 312 ROXBORO #1- 50121	D FOS 312 ROXBORO #2- 50121	D FOS 312 ROXBORO #3- 50121	D FOS 315 ROXBORO #3- 50121	D FOS 312 ROXBORO #4- 50121	D FOS 315 ROXBORO #4- 50121	D FOS 311 ROXBORO COMMON-50121	D FOS 312 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 311 MAYO #1-50121	D FOS 312 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	D FOS 311 ROXBORO COMMON-50121	
Bonus Depr Eligibl	#N/A	NO	#N/A	#N/A	#N/A	#N/A	#N/A	No	No	NO	YES	YES	NO	YES	NO	YES	YES	
Initial In Service Y	#N/A	2018	#N/A	#N/A	#N/A	#N/A	#N/A	2018	2018	2019	2019	2019	2019	2019	2019	2018	2018	
Bonus Depr %	50%		50%	50%	50%						40%	40%		40%		50%	50%	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	15,960
201802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	15,960
201803	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	15,960
201804	-	-	-	2,958,647	-	-	-	-	-	-	-	-	-	-	-	-	15,960	2,974,608
201805	-	-	-	3,001,078	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,017,039
201806	-	-	-	3,025,289	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,041,250
201807	-	-	-	3,075,342	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,091,303
201808	-	-	-	3,110,735	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,126,695
201809	-	-	-	3,124,479	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,140,440
201810	-	-	-	3,138,371	-	-	-	-	-	-	-	-	-	-	-	-	15,960	3,154,331
201811	-	-	43,907,080	3,198,636	-	-	-	-	-	-	-	-	-	-	-	10,996,024	15,960	58,117,701
201812	-	-	43,953,373	3,206,089	-	-	-	-	-	-	-	-	-	-	-	11,192,993	15,960	58,368,415
201901	-	-	44,707,015	3,209,400	-	-	-	-	-	-	-	-	-	-	-	11,221,347	15,960	59,153,723
201902	-	-	45,206,368	3,209,346	-	-	-	-	-	-	-	-	-	-	-	11,378,365	15,960	59,810,039
201903	-	-	45,977,206	3,209,346	148	-	-	-	-	-	5,427,139	-	-	48,143,259	-	11,435,527	15,960	114,208,587
201904	-	-	46,309,642	3,209,346	148	-	-	-	-	-	5,472,022	8,985,508	-	49,435,157	-	11,270,275	15,960	124,698,058
201905	-	-	46,201,251	3,209,346	148	-	-	-	-	-	5,506,137	9,129,387	-	50,165,779	-	11,361,698	15,960	125,589,706
201906	-	-	46,249,852	3,209,346	148	-	-	-	-	-	5,639,786	9,327,391	-	50,845,637	-	11,568,520	15,960	126,856,640
201907	-	-	46,458,186	3,209,346	148	-	-	-	-	-	5,646,454	9,396,738	-	51,348,818	-	11,532,972	15,960	127,608,624
201908	(153,356)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,699,778	9,548,292	-	51,528,893	-	11,763,598	15,960	128,070,846
201909	(100,553)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,843,890	9,797,184	-	51,963,946	-	11,920,039	15,960	129,108,148
201910	(100,553)	-	46,465,023	3,209,346	148	-	-	-	-	-	5,828,894	10,061,859	-	52,288,417	-	11,963,842	15,960	129,732,937
201911	(100,553)	-	46,456,551	3,209,346	148	-	-	-	-	-	5,908,257	9,799,788	-	52,209,195	-	12,185,076	15,960	129,683,770
201912	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,823,981	-	52,500,827	-	12,201,762	15,960	130,019,286
202001	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,830,650	-	52,782,085	-	12,198,754	15,960	130,304,205
202002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred environmental costs
For the test period ended December 31, 2018

NC 1110
Second Settlement

Tax Basis for Bonus Depreciation ADIT

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description																		
Bonus Depr Eligibl	YES	NO	YES	YES	YES	NO	NO	No	No	NO	YES	YES	NO	YES	NO	YES	YES	
Inititial In Service Y	2018	2018	2018	2018	2018	2018	2018	2018	2018	2019	2019	2019	2019	2019	2019	2018	2018	
Bonus Depr %	50%		50%	50%	50%						40%	40%		40%		50%	50%	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201803	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201804	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201805	-	-	-	2,958,647	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201806	-	-	-	3,001,078	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201807	-	-	-	3,025,289	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201808	-	-	-	3,075,342	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201809	-	-	-	3,110,735	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201810	-	-	-	3,124,479	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201811	-	-	-	3,138,371	-	-	-	-	-	-	-	-	-	-	-	-	15,960	
201812	-	-	43,907,080	3,198,636	-	-	-	-	-	-	-	-	-	-	-	10,996,024	15,960	
201901	-	-	43,953,373	3,206,089	-	-	-	-	-	-	-	-	-	-	-	11,192,993	15,960	
201902	-	-	44,707,015	3,209,400	-	-	-	-	-	-	-	-	-	-	-	11,221,347	15,960	
201903	-	-	45,206,368	3,209,346	-	-	-	-	-	-	-	-	-	-	-	11,378,365	15,960	
201904	-	-	45,977,206	3,209,346	148	-	-	-	-	-	5,427,139	-	-	48,143,259	-	11,435,527	15,960	
201905	-	-	46,309,642	3,209,346	148	-	-	-	-	-	5,472,022	8,985,508	-	49,435,157	-	11,270,275	15,960	
201906	-	-	46,201,251	3,209,346	148	-	-	-	-	-	5,506,137	9,129,387	-	50,165,779	-	11,361,698	15,960	
201907	-	-	46,249,852	3,209,346	148	-	-	-	-	-	5,639,786	9,327,391	-	50,845,637	-	11,568,520	15,960	
201908	-	-	46,458,186	3,209,346	148	-	-	-	-	-	5,646,454	9,396,738	-	51,348,818	-	11,532,972	15,960	
201909	(153,356)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,699,778	9,548,292	-	51,528,893	-	11,763,598	15,960	
201910	(100,553)	-	46,458,186	3,209,346	148	-	-	-	-	-	5,843,890	9,797,184	-	51,963,946	-	11,920,039	15,960	
201911	(100,553)	-	46,465,023	3,209,346	148	-	-	-	-	-	5,828,894	10,061,859	-	52,288,417	-	11,963,842	15,960	
201912	(100,553)	-	46,456,551	3,209,346	148	-	-	-	-	-	5,908,257	9,799,788	-	52,209,195	-	12,185,076	15,960	
202001	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,823,981	-	52,500,827	-	12,201,762	15,960	
202002	(100,553)	-	46,456,507	3,209,346	148	-	-	-	-	-	5,911,306	9,830,650	-	52,782,085	-	12,198,754	15,960	

Accumulated Deferred Income taxes

Project	$20,087,848	160920A01	20087848	20095627	20095627	20095628	20095628	20095629	20095629	CCROX148	CMY010141	CMY010188	CMY010189	CRX000139	CRX000212	CRX000213	CRXWAREHS	Grand Total
Project Description																		
Tax Rate	23.1693%																	
201801	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201803	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201804	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(3,698)
201805	-	-	-	(685,498)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(689,196)
201806	-	-	-	(695,329)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(699,027)
201807	-	-	-	(700,938)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(704,636)
201808	-	-	-	(712,535)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(716,233)
201809	-	-	-	(720,735)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(724,433)
201810	-	-	-	(723,920)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(727,618)
201811	-	-	-	(727,139)	-	-	-	-	-	-	-	-	-	-	-	-	(3,698)	(730,836)
201812	-	-	(10,172,963)	(741,102)	-	-	-	-	-	-	-	-	-	-	-	(2,547,702)	(3,698)	(13,465,465)
201901	-	-	(10,183,689)	(742,828)	-	-	-	-	-	-	-	-	-	-	-	(2,593,338)	(3,698)	(13,523,554)
201902	-	-	(10,358,303)	(743,596)	-	-	-	-	-	-	-	-	-	-	-	(2,599,908)	(3,698)	(13,705,504)
201903	-	-	(10,473,999)	(743,583)	-	-	-	-	-	-	-	-	-	-	-	(2,636,287)	(3,698)	(13,857,568)
201904	-	-	(10,652,597)	(743,583)	(34)	-	-	-	-	-	(1,257,430)	-	-	(11,154,456)	-	(2,649,532)	(3,698)	(26,461,331)
201905	-	-	(10,729,620)	(743,583)	(34)	-	-	-	-	-	(1,267,829)	(2,081,879)	-	(11,453,780)	-	(2,611,244)	(3,698)	(28,891,668)
201906	-	-	(10,704,507)	(743,583)	(34)	-	-	-	-	-	(1,275,733)	(2,115,215)	-	(11,623,060)	-	(2,632,426)	(3,698)	(29,098,256)
201907	-	-	(10,715,767)	(743,583)	(34)	-	-	-	-	-	(1,306,699)	(2,161,091)	-	(11,780,578)	-	(2,680,345)	(3,698)	(29,391,796)
201908	-	-	(10,764,037)	(743,583)	(34)	-	-	-	-	-	(1,308,244)	(2,177,158)	-	(11,897,162)	-	(2,672,109)	(3,698)	(29,566,025)
201909	35,532	-	(10,764,037)	(743,583)	(34)	-	-	-	-	-	(1,320,599)	(2,212,272)	-	(11,938,884)	-	(2,725,543)	(3,698)	(29,673,119)
201910	23,297	-	(10,764,037)	(743,583)	(34)	-	-	-	-	-	(1,353,989)	(2,269,939)	-	(12,039,683)	-	(2,761,790)	(3,698)	(29,913,455)
201911	23,297	-	(10,765,621)	(743,583)	(34)	-	-	-	-	-	(1,350,514)	(2,331,262)	-	(12,114,861)	-	(2,771,939)	(3,698)	(30,058,214)
201912	23,297	-	(10,763,658)	(743,583)	(34)	-	-	-	-	-	(1,368,902)	(2,270,542)	-	(12,096,505)	-	(2,823,197)	(3,698)	(30,046,822)
202001	23,297	-	(10,763,648)	(743,583)	(34)	-	-	-	-	-	(1,369,608)	(2,276,148)	-	(12,164,074)	-	(2,827,063)	(3,698)	(30,124,559)
202002	23,297	-	(10,763,648)	(743,583)	(34)	-	-	-	-	-	(1,369,608)	(2,277,693)	-	(12,229,240)	-	(2,826,366)	(3,698)	(30,190,573)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018

NC-2200
Second Settlement

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

This pro-forma adjusts income taxes to reflect the tax impact that results from annualizing interest expense based on the end-of-period, adjusted rate base.

The impact to income taxes was determined as follows:

First, multiply rate base after all pro-forma adjustments have been made by the long-term debt ratio to calculate an adjusted long-term debt balance. Second, multiply the adjusted long-term debt balance by the end of year cost of long-term debt to calculate annualized interest expense. Third, subtract interest expense incurred during the test period from annualized interest expense and multiply the difference by the statutory tax rate.

October Update

Reflects changes for October updates to actuals

November Update

Reflects changes for November actuals

December Update

Reflects changes for December actuals

January Update

Reflects changes for January actuals

February Update

Reflects changes for February actuals

Second Settlement

Reflects changes for settlement adjustments flowing from other proformas

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2200
Second Settlement

Line No.	Description	Source	Total NC Retail						
1			Second Settlement	Second Supplemental S	Second Supplemental	April	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**								
3									
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -
5									
6	Electric operating expenses:								
7	Operation and maintenance								
8	Fuel used in electric generation		-	-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-	-
14	Income taxes	NC-2201	387	2,104	3,081	3,324	3,704	123	264
15	Amortization of investment tax credit		-	-	-	-	-	-	-
16									
17	Total electric operating expenses	Sum L8 through L15	387	2,104	3,081	3,324	3,704	123	264
18									
19	Operating income	L4 - L17	$ (387)	$ (2,104)	$ (3,081)	$ (3,324)	$ (3,704)	$ (123)	$ (264)
20									
21	Notes:								
22	Revenue: positive number increases revenue / negative number decreases revenue								
23	Expense: positive number increases expense / negative number decreases expense								
24									
25									
26	**Pro Formas Impacting Rate Base Line Items**								
27									
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-	-
31									
32	Add:								
33	Materials and supplies		-	-	-	-	-	-	-
34	Working capital investment		-	-	-	-	-	-	-
35									
36									
37	Less:								
38	Accumulated deferred taxes		-	-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-	-
40									
41									
42	Construction work in progress		-	-	-	-	-	-	-
43									
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45									
46	Note:								
47	Rate Base: positive number increases rate base / negative number decreases rate base								

I/A

Duke Energy Progress, LLC — NC-2201
Docket No. E-2, Sub 1219 — Second Settlement
Synchronize interest expense with end of period rate base
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Total System Col [a]		NC Retail Allocation Col [b]		Total NC Retail Col [c]	
1							
2	Rate base before pro forma adjustments	$ 14,580,739	[1]	67.6169%	[2]	$ 9,859,050	[1]
3							
4	Pro forma rate base before working capital adjustment	$ 15,995,329	[3]			$ 10,815,553	
5							
6	Long-term debt ratio	48.0000%	[4]			48.0000%	[4]
7	Calculated long-term debt (L4 x L6)	$ 7,677,758				$ 5,191,465	
8							
9	End of year cost of long-term debt	4.0449%	[4]			4.0449%	[4]
10	Annualized interest expense (L7 x L9)	$ 310,561				$ 209,992	
11							
12	Incurred interest expense	315,466	[5]	67.0949%	[6]	211,661	
13	Less interest on customer deposits	(8,643)	[7]			(7,971)	[7]
14	Net interest expense	306,823				203,690	
15							
16	Increase / <decrease> to interest costs (L10 - L14)	$ 3,738				$ (1,669)	
17							
18	Statutory tax rate	23.1693%	[8]			23.1693%	[8]
19	Impact to income taxes (-L16 x L18)	$ (866)				$ 387	
20							
21	Impact to operating income (-L19)	$ 866				$ (387)	

[1] Smith Exhibit 1, Page 1, Line 12
[2] NC Retail Allocation Factor - Calculation: L2, Col [c] / L2, Col [a]
[3] Calculation: L4, Col [c] / L2, Col [b]
[4] Smith Exhibit 1, Page 2, Line 1
[5] Cost of Service, E-1 Item 45a, Total Other Interest Expense, Line 702
[6] NC Retail Allocation Factor - Net Book Plant
[7] Smith Exhibit 1, Page 1, Line 7
[8] NC-0104 - 2019 Tax Rate, Line 10

Duke Energy Progress, LLC NC-2300
Docket No. E-2, Sub 1219 Second Settlement
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment
This pro forma adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required as a result of the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 order in Docket No. M-100 Sub 137.

October Update
Reflects changes for October updates to actuals

November Update
Reflects changes for November actuals

December Update
Reflects changes for December actuals

January Update
Reflects changes for January 2020 actuals

February Update
Reflects changes for February 2020 actuals and revised E&Y Lead Lag Study

Settlement Update
Reflects changes for settlement adjustments flowing from other proformas

Second Settlement
Reflects changes for settlement adjustments flowing from other proformas

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
(Dollars in thousands)

NC-2300
Second Settlement

Line No.	Description	Source	Present	Proposed	Present	Proposed	Total NC Retail Present	Proposed	Present	Proposed	Present	Proposed
1			Second Settlement		Second Supplemental		Partial Settlement		Application		Change	
2	**Pro Formas Impacting Income Statement Line Items**											
3												
4	Electric operating revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5												
6	Electric operating expenses											
7	Operation and maintenance											
8	Fuel used in electric generation		-	-	-	-	-	-	-	-	-	-
9	Purchased power		-	-	-	-	-	-	-	-	-	-
10	Other operation and maintenance expense		-	-	-	-	-	-	-	-	-	-
11	Depreciation and amortization		-	-	-	-	-	-	-	-	-	-
12	General taxes		-	-	-	-	-	-	-	-	-	-
13	Interest on customer deposits		-	-	-	-	-	-	-	-	-	-
14	Income taxes	NC-2301 & NC-2302	99	(234)	86	(248)	77	(234)	122	(337)	(23)	103
15	Amortization of investment tax credit		-	-	-	-	-	-	-	-	-	-
16												
17	Total electric operating expenses	Sum L8 through L15	99	(234)	86	(248)	77	(234)	122	(337)	(23)	103
18												
19	Operating income	L4 - L17	$ (99)	$ 234	$ (86)	$ 248	$ (77)	$ 234	$ (122)	$ 337	$ 23	$ (103)
20												
21	Notes:											
22	Revenue: positive number increases revenue / negative number decreases revenue											
23	Expense: positive number increases expense / negative number decreases expense											
24												
25												
26	**Pro Formas Impacting Rate Base Line Items**											
27												
28	Electric plant in service		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-	-	-	-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-	-	-	-	-	-	-
31												
32	Add:											
33	Materials and supplies		-	-	-	-	-	-	-	-	-	-
34	Working capital investment	NC-2302	(22,061)	51,938	(19,273)	55,523	(17,314)	52,407	(27,013)	74,407	4,952	(22,469)
35												
36												
37	Less:											
38	Accumulated deferred taxes		-	-	-	-	-	-	-	-	-	-
39	Operating reserves		-	-	-	-	-	-	-	-	-	-
40												
41												
42	Construction work in progress		-	-	-	-	-	-	-	-	-	-
43												
44	Total impact to rate base	Sum L30 through L42	$ (22,061)	$ 51,938	$ (19,273)	$ 55,523	$ (17,314)	$ 52,407	$ (27,013)	$ 74,407	$ 4,952	$ (22,469)
45												
46	Note:											
47	Rate Base: positive number increases rate base / negative number decreases rate base											

Smith Second Settlement Exhibit 1

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2301
Second Settlement

Line No.	Description	NC Retail – Financials: Adjusted with CWC (a)	NC Retail – Financials: Revenue Increase (b) = (c) - (a)	NC Retail – Financials: Adjusted w/Increase (c) = (n)	NC Retail – Iteration 1: Increase (d) = (e) - (a)	NC Retail – Iteration 1: With Increase (e) = (a) + (d)	NC Retail – Iteration 1: Weighted Lead Lag Days (f)
1	Total Adjusted Present Revenue	$ 3,354,802 [1]					42.09 [1]
2	Revenue Increase (L3)	-	408,932		404,532		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	3,354,802	408,932	3,763,734	404,532	3,759,335	42.06 [8]
4							
5	Operating Expenses:						
6	Fuel Used in Electric Generation	848,169 [1]	-	848,169		848,169	28.49 [1]
7	Purchased Power	156,798 [1]	-	156,798		156,798	33.44 [1]
8							
9	Operation & Maintenance Expense	863,460 [1]					37.39 [1]
10	Revenue Increase (L11)		1,509		1,493		37.32 [7]
11	Operation and Maintenace Expense with Increase	863,460	1,509	864,969	1,493 [3]	864,953	37.39 [8]
12							
13	Total Adjusted Depreciation and Amortization	905,941 [1]	-	905,941		905,941	0.00 [1]
14	Total Adjusted General Taxes	104,578 [1]	-	104,578		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits	7,971 [1]	-	7,971		7,971	137.50 [1]
16							
17	Net Income Taxes	63,330 [1]					-0.02 [1]
18	Revenue Increase (L19)		94,163		93,381		-20.60 [7]
19	Income Taxes with Increase	63,330	94,163	157,494	93,381 [4]	156,712	-12.28 [8]
20							
21	EDIT Amortization	(30,548) [1]	-	(30,548)		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit	(3,614) [1]	-	(3,614)		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	2,916,085	95,673	3,011,758	94,874	3,010,960	25.03 [9]
24							
25	Income for Return (L3 - L23)	438,717	313,259	751,976	309,658	748,375 [5]	24.56 [9]
26	Interest Expense	209,564 [1]	1,008	210,572	-	209,564 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	229,153	312,251	541,404	309,658	538,811	0.00 [1]
28							
29	Total Requirement (L23 + L25 = L3)	$ 3,354,802		$ 3,763,734		$ 3,759,335	24.94 [9]
30							
31	Rate Base [CWC Solved for Through Iterative Process]	$ 10,793,491 [1]	$ 51,938	$ 10,845,429		$ 10,793,491	
32							
33	Overall Rate of Return (L25 / L31)	4.06%		6.93%		6.93%	
34	Target Rate of Return	6.93% [2]		6.93% [2]		6.93% [2]	
35							
36			Revenue	Adjusted			
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase	Adjusted	Increase	w/Increase			
38	Annual Requirement (L3 and/or L29)	$ 3,354,802		$ 3,763,734		$ 3,759,335	
39	Daily Requirement (L38 / 365 Days)	$ 9,191		$ 10,312		$ 10,300	
40	Net Lag Days	13.57 [1]		17.13		17.12	
41							
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 124,740	$ 51,938	$ 176,677	$ 51,634	$ 176,374	
43	Add: Working Capital Related to NC Sales Tax	$ 4,760 [1]		$ 4,760 [1]			
44	Total Cash Working Capital Requirements (L42 + L43)	$ 129,499	$ 51,938	$ 181,437			

NC-2301
Second Settlement

NC-2301
Second Settlement

NC-2301
Second Settlement

Line No.	Description	NC Retail – Iteration 2: Increase (g) = (h) - (e)	NC Retail – Iteration 2: With Increase (h) = (e) + (g)	NC Retail – Iteration 2: Weighted Lead Lag Days (i)	NC Retail – Iteration 3: Increase (j) = (k) - (h)	NC Retail – Iteration 3: With Increase (k) = (h) + (j)	NC Retail – Iteration 3: Weighted Lead Lag Days (l)	NC Retail – Iteration 4: Increase (m) = (n) - (k)	NC Retail – Iteration 4: With Increase (n) = (k) + (m)	NC Retail – Iteration 4: Weighted Lead Lag Days (o)
1	Total Adjusted Present Revenue			42.09 [1]			42.09 [1]			42.09 [1]
2	Revenue Increase (L3)	4,374		41.88 [7]	26		41.88 [7]	0		41.88 [7]
3	Revenues [Solved Through Iterative Process to Produce Target ROR] (L23 + L25)	4,374	3,763,708	42.06 [8]	26	3,763,734	42.06 [8]	0	3,763,734	42.06 [8]
4										
5	Operating Expenses:									
6	Fuel Used in Electric Generation		848,169	28.49 [1]		848,169	28.49 [1]		848,169	28.49 [1]
7	Purchased Power		156,798	33.44 [1]		156,798	33.44 [1]		156,798	33.44 [1]
8										
9	Operation & Maintenance Expense			37.39 [1]			37.39 [1]			37.39 [1]
10	Revenue Increase (L11)	16	16	37.32 [7]	0	16	37.32 [7]	0	16	37.32 [7]
11	Operation and Maintenace Expense with Increase	16 [3]	864,969	37.39 [8]	0 [3]	864,969	37.39 [8]	0 [3]	864,969	37.39 [8]
12										
13	Total Adjusted Depreciation and Amortization		905,941	0.00 [1]		905,941	0.00 [1]		905,941	0.00 [1]
14	Total Adjusted General Taxes		104,578	138.26 [1]		104,578	138.26 [1]		104,578	138.26 [1]
15	Total Adjusted Interest on Customer Deposits		7,971	137.50 [1]		7,971	137.50 [1]		7,971	137.50 [1]
16										
17	Net Income Taxes			-0.02 [1]			-0.02 [1]			-0.02 [1]
18	Revenue Increase (L19)	777		-20.60 [7]	5		-20.60 [7]	0		-20.60 [7]
19	Income Taxes with Increase	777 [4]	157,489	-12.32 [8]	5 [4]	157,494	-12.32 [8]	0 [4]	157,494	-12.32 [8]
20										
21	EDIT Amortization		(30,548)	0.00 [1]		(30,548)	0.00 [1]		(30,548)	0.00 [1]
22	Amortization of Investment Tax Credit		(3,614)	0.00 [1]		(3,614)	0.00 [1]		(3,614)	0.00 [1]
23	Total Operating Expense (L6+L7+L11+L13+L14+L15+L19+L22)	793	3,011,753	25.02 [9]	5	3,011,758	25.02 [9]	0	3,011,758	25.02 [9]
24										
25	Income for Return (L3 - L23)	3,580	751,955 [5]	24.56 [9]	21	751,976 [5]	24.56 [9]	0	751,976 [5]	24.56 [9]
26	Interest Expense	1,003	210,566 [6]	87.70 [1]	6	210,572 [6]	87.70 [1]	0	210,572 [6]	87.70 [1]
27	Return for Equity (L25 - L26)	2,578	541,389	0.00 [1]	15	541,404	0.00 [1]	0	541,404	0.00 [1]
28										
29	Total Requirement (L23 + L25 = L3)		$ 3,763,708	24.93 [9]		$ 3,763,734	24.93 [9]		$ 3,763,734	24.93 [9]
30										
31	Rate Base [CWC Solved for Through Iterative Process]	$ 51,634	$ 10,845,126		$ 301	$ 10,845,427		$ 2	$ 10,845,429	
32										
33	Overall Rate of Return (L25 / L31)		6.93%			6.93%			6.93%	
34	Target Rate of Return		6.93% [2]			6.93% [2]			6.93% [2]	
35										
36										
37	Calculation of Change in Cash Working Capital (CWC) due to Revenue Increase									
38	Annual Requirement (L3 and/or L29)		$ 3,763,708			$ 3,763,734				
39	Daily Requirement (L38 / 365 Days)		$ 10,312			$ 10,312				
40	Net Lag Days		17.13			17.13				
41										
42	Est. CWC Req. Before Sales Tax Requirement (L39 x L40)	$ 301	$ 176,675		$ 2	$ 176,677				
43	Add: Working Capital Related to NC Sales Tax									
44	Total Cash Working Capital Requirements (L42 + L43)									

Notes
[1] NC-2302, Adjustment to cash working capital for present revenue annualized
[2] NC-2304, Total ROR
[3] Reg fee x revenue requirement
[4] L27 / (1 - Tax Rate) - L27
[5] Line 31 x Rate of Return
[6] Rate Base x Debt Rate x Debt Ratio
[7] Docket No. E-2, Sub 1219, E-1 Item 14, Lead Lag
[8] Calculation of Average Lead/Lag Day
[9] New weighted averages are calculated.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust cash working capital for present revenue annualized and proposed revenue
For the test period ended December 31, 2018
Dollars in Thousands

NC-2302
Second Settlement

Line No.	Description	NC Retail – Financials: Per Books [1] (a)	Adjustments [3] (b)	Adjusted Before Change in CWC [3] (c) = (a) + (b)	Change in CWC (d)	Adjusted with CWC (e) = (c) + (d)	Lead Lag Days: Per Books [1] (f)	Adjustments [1] (g)	Adjusted Before Increase [6] (h) = (f) + (g)
1	**Rate Schedule Revenue**								
2	Rate Revenues	$ 3,575,788		$ 3,575,788			41.88		41.88
3	Total Revenue Lag Sales for Resale	134,915		134,915			33.73		33.73
4	Provisions For Rate Refunds	(104,546)		(104,546)			41.88		41.88
5	Forfeited Discounts	7,664		7,664			72.30		72.30
6	Miscellaneous Revenues	5,506		5,506			76.00		76.00
7	RENT - (454) - DIST PLT REL	4,466		4,466			41.63		41.63
8	RENT - (454) - DIST POLE RENTAL REV	10,901		10,901			182.00		182.00
9	RENT - (454) - TRANS PLT REL	382		382			41.63		41.63
10	RENT - (454) - ADD FAC - WHLS	-		-			0.00		0.00
11	RENT - (454) - ADD FAC - RET X LIGHTING	4,617		4,617			41.63		41.63
12	RENT - (454) - ADD FAC - LIGHTING	3,849		3,849			41.63		41.63
13	RENT - (454) - OTHER	3,413		3,413			68.21		68.21
14	OTHER ELEC REV (456) - PROD PLT REL	10,549		10,549			41.88		41.88
15	NC-0100 Annualize Retail revenues for current rates		(201,667)	(201,667)				41.88	41.88
16	NC-0300 Normalize for weather		(72,510)	(72,510)				41.88	41.88
17	NC-0400 Annualize revenues for customer growth		(8,366)	(8,366)				41.88	41.88
18	NC-0500 Eliminate unbilled revenues		11,826	11,826				41.88	41.88
19	NC-0600 Adjust costs recovered through non-fuel riders		(27,830)	(27,830)				41.88	41.88
20	NC-2900 Storm Deferral NC FMD		-	-				41.88	41.88
21	NC-3000 Adjust Other Revenue		(4,155)	(4,155)				98.96	98.96
22	Rounding		-	-				41.88	41.88
23	Revenue - Adjustments (Sum Lines 15 through 22)	-	(302,701)	(302,701)					
24									
25	Total Adjusted Revenue (L2 + L23)	$ 3,657,503	$ (302,701)	$ 3,354,802	$ -	$ 3,354,802	42.13	(0.05)	42.09
26									
27	**Operating Expenses:**								
28	Fuel Used in Electric Generation								
29	OM Prod Energy - Fuel	$ 863,120		$ 863,120			28.49		28.49
30	RECS Consumption Expense	18,522		18,522			28.49		28.49
31	NC-0200 Update fuel costs to approved rate		11,436	11,436				28.49	28.49
32	NC-0300 Normalize for weather		(20,432)	(20,432)				28.49	28.49
33	NC-0400 Annualize revenues for customer growth		(5,955)	(5,955)				28.49	28.49
34	NC-0600 Adjust costs recovered through non-fuel riders		(18,522)	(18,522)				28.49	28.49
35	NC-2900 Storm Deferral NC FMD		-	-				28.49	28.49
36	Rounding		-	-				28.49	28.49
37	Fuel Used in Electric Generation - Adjustments (Sum Lines 31 through 36)	-	(33,473)	(33,473)					
38									
39	Total Adjusted Fuel Used in Electric Generation (L29 + L37)	$ 881,642	$ (33,473)	$ 848,169	$ -	$ 848,169	28.49	0.00	28.49
40									
41	Purchased Power								
42	OM PROD PURCHASES - CAPACITY COST	$ 67,280		$ 67,280			30.29		30.29
42	OM PROD PURCHASES - ENERGY COST	365,384		365,384			30.29		30.29
43	OM DEFERRED FUEL EXPENSE	(273,901)		(273,901)			28.49		28.49
43	NC-3500 Adjust purchased power		(1,965)	(1,965)				30.29	30.29
44	Rounding		-	-					
45	Purchased Power - Adjustments (Sum Lines 43 through 44)	-	(1,965)	(1,965)					
46									
47	Total Adjusted Purchased Power (L42 + L45)	$ 158,763	$ (1,965)	$ 156,798	$ -	$ 156,798	33.40	0.04	33.44
48									
49	Operation & Maintenance Expense								
50	Total Labor Expense	$ 430,295		$ 430,295			37.07		37.07
46	Pension and Benefits	76,271		76,271			13.97		13.97
47	Regulatory Commission Expense	7,038		7,038			93.25		93.25
48	Property Insurance	(526)		(526)			(222.30)		(222.30)
49	Injuries & Damages - Workman's Compensation	197		197			0.00		0.00
50	Uncollectible Accounts	8,937		8,937			0.00		0.00
51	Remaining Other Oper & Maint Expense	528,607		528,607			40.52		40.52
51	NC-0100 Annualize Retail revenues for current rates		(744)	(744)				37.32	37.32
52	NC-0200 Update fuel costs to approved rate		-	-				37.32	37.32
53	NC-0300 Normalize for weather		(268)	(268)				37.32	37.32
54	NC-0400 Annualize revenues for customer growth		(31)	(31)				37.32	37.32
55	NC-0600 Adjust costs recovered through non-fuel riders		(136,143)	(136,143)				37.32	37.32
56	NC-0700 Adjust O&M for executive compensation		(2,586)	(2,586)				37.07	37.07
57	NC-1200 Annualize O&M non-labor expenses		2,345	2,345				33.30	33.30
58	NC-1300 Normalize O&M labor expenses		(19,235)	(19,235)				37.07	37.07
59	NC-1400 Update benefits costs		(6,358)	(6,358)				13.97	13.97
60	NC-1500 Levelize nuclear refueling outage costs		(6,190)	(6,190)				40.52	40.52
61	NC-1600 Amortize rate case costs		701	701				0.00	0.00
62	NC-1700 Adjust aviation expenses		(1,657)	(1,657)				37.32	37.32
63	NC-1800 Adjust for approved regulatory assets and liabilities		1,603	1,603				0.00	0.00
64	NC-1900 Adjust for Merger Related Costs		(4,039)	(4,039)				37.32	37.32
65	NC-2000 Amortize Severance Costs		(24,140)	(24,140)				37.07	37.07
66	NC-2500 Adjust for credit card fees		5,269	5,269				40.52	40.52
67	NC-2700 Adjust vegetation management expenses		5,757	5,757				40.52	40.52
68	NC-2900 Storm Deferral NC		-	-				37.32	37.32
69	NC-3000 Adjust Other Revenue		(5)	(5)				37.32	37.32
70	NC-3100 Adjust for change in NCUC Reg Fee		(234)	(234)				93.25	93.25
71	NC-3200 Reflect retirement of Asheville Steam Generating Plant		(6,413)	(6,413)				37.32	37.32
72	NC-3300 Adjust for CertainTeed payment Obligation		-	-				37.32	37.32
73	NC-3400 Amortize deferred balance Asheville Combined Cycle		(1,459)	(1,459)				37.32	37.32
74	NC-3800 Remove certain Settlement Items		(2,834)	(2,834)				37.32	37.32
75	NC-3900 Normalize for storm costs		9,300	9,300				37.32	37.32
76	Rounding		-	-					
77	Operation & Maintenance Expense - Adjustments (Sum Lines 51 through 72)	-	(187,359)	(187,359)					
78									
79	Total Adjusted Operation & Maintenance Expense (L50 + L77)	$ 1,050,819	$ (187,359)	$ 863,460	$ -	$ 863,460	37.32	0.08	37.39
80									
81	Depreciation and Amortization	$ 669,787		$ 669,787			0.00		0.00
82	NC-0200 Update fuel costs to approved rate		-	-				0.00	0.00
83	NC-0600 Adjust costs recovered through non-fuel riders		(58,446)	(58,446)				0.00	0.00
84	NC-0800 Annualize Depreciation on year end plant balances		41,407	41,407				0.00	0.00
85	NC-1000 Adjust for post test year additions to plant in service		68,269	68,269				0.00	0.00
86	NC-1100 Amortize deferred environmental costs		93,023	93,023				0.00	0.00
87	NC-1800 Adjust for approved regulatory assets and liabilities		(3,479)	(3,479)				0.00	0.00
88	NC-1900 Adjust for Merger Related Costs		(184)	(184)				0.00	0.00
89	NC-2600 Adjust for Depreciation for new rates		88,728	88,728				0.00	0.00
90	NC-2800 Adjust reserve for end of life nuclear costs		(1,917)	(1,917)				0.00	0.00
91	NC-2900 Storm Deferral		(1,645)	(1,645)				0.00	0.00
92	NC-3200 Reflect retirement of Asheville Steam Generating Plant		10,201	10,201				0.00	0.00
93	NC-3400 Amortize deferred balance Asheville Combined Cycle		8,897	8,897				0.00	0.00
94	NC-3800 Remove certain Settlement Items		(8,700)	(8,700)				0.00	0.00
95	Rounding		-	-					
96	Depreciation and Amortization - Adjustments (Sum Lines 82 through 95)	-	236,153	236,153					
97									
98	Total Adjusted Depreciation and Amortization (L81 + L96)	$ 669,787	$ 236,153	$ 905,941	$ -	$ 905,941	0.00	0.00	0.00
99									
100	General Taxes								
101	Payroll Taxes	$ 26,288		$ 26,288			48.41		48.41
102	Property Tax	68,133		68,133			186.50		186.50
103	FED HEAVY VEHICLE USE TAX	48		48			0.00		0.00
104	ELECTRIC EXCISE TAX - SC	-		-			0.00		0.00
105	PRIVILEGE TAX	12,244		12,244			(11.97)		(11.97)
106	MISC TAX - NC	(4,517)		(4,517)			60.00		60.00
107	MISC TAX - SC & OTHER STATES	1		1			129.46		129.46
108	PUC LICENSE TAX - SC	-		-			0.00		0.00
109	NC-0600 Adjust costs recovered through non-fuel riders		(6,458)	(6,458)				137.26	137.26
110	NC-0900 Annualize property taxes on year end plant balances		4,064	4,064				186.50	186.50
111	NC-1000 Adjust for post test year additions to plant in service		5,750	5,750				186.50	186.50
112	NC-1300 Normalize O&M labor expenses		(909)	(909)				48.41	48.41
113	NC-1700 Adjust aviation expenses		(18)	(18)				48.41	48.41
114	NC-1800 Adjust for approved regulatory assets and liabilities		5	5				48.41	48.41
115	NC-1900 Adjust for Merger Related Costs		(53)	(53)				48.41	48.41
116	NC-3200 Reflect retirement of Asheville Steam Generating Plant		-	-				186.50	186.50
118	Rounding		-	-					
119	General Taxes - Adjustments (Sum Lines 109 through 118)	-	2,381	2,381					
120									
121	Total Adjusted General Tax (L101 + L119)	$ 102,197	$ 2,381	$ 104,578	$ -	$ 104,578	132.70	5.55	138.26
122									
123	Interest on Customer Deposits	$ 7,971		$ 7,971			137.50		137.50
124	Interest on Customer Deposits - Adjustments			-					
125	Rounding		-	-					
126	Total Adjusted Interest on Customer Deposits (L123 + L124)	$ 7,971	$ -	$ 7,971	$ -	$ 7,971	137.50	0.00	137.50
127									
128	Income Taxes								
129	Federal Income Tax	$ (49,091)		$ (49,091)			44.75		44.75
130	State Income Tax	(2,917)		(2,917)			44.75		44.75
131	Income Tax - Deferred	164,994		164,994			0.00		0.00
132	PF INC TAX-Adjust Income Taxes		(111,127)	(111,127)				(20.60)	(20.60)
133	NC-0600 Adjust costs recovered through non-fuel riders		63,168	63,168				0.00	0.00
134	NC-2100 Adjust NC income taxes for rate change		(2,183)	(2,183)				(20.60)	(20.60)
135	NC-2200 Synchronize interest expense		387	387				(20.60)	(20.60)
136	Rounding		-	-					
137	Income Taxes - Adjustments (Sum Lines 132 through 136)	-	(49,755)	(49,755)					
138									
139	Total Adjusted Income Taxes (L129 + L137)	$ 112,986	$ (49,755)	$ 63,231	$ 99 [5]	$ 63,330	(20.60)	20.58	(0.02)
140									
141	EDIT Amortization	$ -		$ -			0.00		0.00
142	NC-3700 Amortize Prot EDIT		(30,548)	(30,548)				0.00	0.00
143	Rounding		-	-					
144	EDIT Amortization (Sum Lines 142 through 143)	-	(30,548)	(30,548)					
145									
146	Total Adjusted EDIT Amortization (L141 + L144)	$ -	$ (30,548)	$ (30,548)	$ -	$ (30,548)	0.00	0.00	0.00
147									
148	Amortization of Investment Tax Credit	$ (2,134)		$ (2,134)			0.00		0.00
149	NC-0800 Annualize Depreciation on year end plant balances		(1,481)	(1,481)				0.00	0.00
150	Rounding		-	-					
151	Amort. of Investment Tax Credit - Adjustments (Sum Lines 149 through 150)	-	(1,481)	(1,481)					
152									
153	Total Adjusted Amortization of Investment Tax Credit (L148 + L151)	$ (2,134)	$ (1,481)	$ (3,614)	$ -	$ (3,614)	0.00	0.00	0.00
154									
155	Total Operating Expense (L39+L47+L79+L98+L121+L126+L139+L153)	$ 2,982,032	$ (66,046)	$ 2,915,986	$ 99	$ 2,916,085	27.48	(0.99)	26.49
156									
157	Income for Return (L25 - L155)	675,472	(236,656)	438,816	(99)	438,717	27.48	14.49	41.97
158	Interest Expense	211,661	(1,669)	209,992 [4]	(428) [4]	209,564	87.70	0.00	87.70 [1]
159	Return for Equity (L157 - L158)	463,810	(234,986)	228,824	329	229,153	0.00	0.00	0.00 [1]
160									
161	Total Requirement (L155 + L157 = L25)	$ 3,657,503		$ 3,354,802		$ 3,354,802	27.48	1.03	28.51 [6]
162									
163	RATE BASE	$ 9,859,050 [3]	$ 956,503	$ 10,815,553 [3]	$ (22,061)	$ 10,793,491			
164									
165	Overall Rate of Return (L157 / L163)	6.85%		4.06%		4.06%			

Line No.	Description	Per Books	Change in CWC	Adjusted
166				
167				
168	Calculation of Change in Cash Working Capital (CWC) due to Adjustments			
169	Revenue Lag Days	42.13		42.09
170	Requirement Lead Days	27.48		28.51
171				
172	Net Lag Days (L169 - L170)	14.65		13.57
173				
174	Annual Requirement	$ 3,657,503		$ 3,354,802
175	Daily Requirement (L174 / 365 Days)	$ 10,021		$ 9,191
176	Net Lag Days (L172, Rounded Per Books)	14.65		13.57
177	Est. CWC Req. Before Sales Tax Requirement (L175 x L176)	$ 146,801		$ 124,740
178				
179	Add: Working Capital Related to NC Sales Tax	$ 4,760 [2]		$ 4,760 [2]
180				
181	Total Cash Working Capital Requirements (L177 + L179)	$ 151,561	$ (22,061)	$ 129,499

Notes:
[1] NC 2305: Revised Lead Lag Study (E-1 Item 14)
[2] NC 2303 Summary
[3] Docket No. E-2, Sub 1219, Smith Exhibit 1 Rebuttal
[4] Rate Base x NC-2304-Inputs
[5] Interest Expense: - L158 x Tax Rate: 23.1693%
[6] New weighted averages calculated.

NC-2303
Second Settlement

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the test period ended December 31, 2018
Dollars in Thousands

Revised E-1 Item 14

Line No	Description	Actual Annual Expense	Lead (Lag) Days	Weighted Amount
		[A]	[B]	[C]
	Calculation of NC Retail Amount:			
1	Total Revenue Lag	$ (3,657,503)	42.13	$ (154,105,865)
2				
3	Operation & Maintenance Expense	$ 2,091,224	33.30	$ 69,630,312
4	Depreciation and Amortization	669,787	0.00	-
5	Taxes Other Than Income Taxes	102,197	132.70	13,561,920
6	Interest on Customer Deposits	7,971	137.50	1,096,011
7	Net Income Taxes	112,986	-20.60	(2,327,337)
8	ITC	(2,134)	0.00	-
9	Income for Return	675,472	27.48	18,562,554
10	Total Requirements (Sum L3:L9)	$ 3,657,503	27.48	$ 100,523,460
11				
12	Revenue Lag Days (L1)		42.13	
13	Requirements Lead Days (-L10)		-27.48	
14	Net Lag Days (L12 + L13)		14.65	
15	Daily Requirements (Line 9, Col. A divided by 365)			$ 10,020.56
16				
17	Estimated Cash Working Capital Requirements (L14 x L15)			$ 146,801
18	Add: Cash Working Capital Related to NC Sales Tax			4,760
19	Total Cash Working Capital Requirements (L17 + L18)			$ 151,561
20				
21	**Calculation of Total Company and Jurisdictional Amounts**:			
22	NC Retail Factor			67.0949% [1]
23				
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 225,890
25				

[1] NC Retail Allocation Factor - Net Book Plant

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjustment to Cash Working Capital - Input Worksheet
For the test period ended December 31, 2018

NC-2304
Second Settlement

Line No	Description	Rate		Ratio		Weighted	
1	Debt	4.04%	[1]	48.00%	[1]	1.9416%	[2]
2	Equity	9.60%	[1]	52.00%	[1]	4.9920%	[3]
3	Total ROR (L1 + L2)					6.9336%	
4							
5	Statutory tax rate	23.1693%	[4]				
6	Statutory regulatory fee percentage rate	0.1297%	[5]				
7	Uncollectibles rate	0.24%	[6]				

Notes:
[1] Smith Exhibit 1, Page 2
[2] Debt Rate x Debt Ratio
[3] ROE x Equity Ratio
[4] NC-0104 - 2019 Tax Rate, Line 10
[5] NC-0103 - NCUC Statutory Regulatory Fee Percentage Rate, Docket No. M-100, Sub 142
[6] NC-0105 - Development of Uncollectibles Rate

Supplemental E-1 Item 14

NC-2305
Second Settlement

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Cash Working Capital for NC Retail Operations - Lead Lag Detail
For the test period ended December 31, 2018

Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	System YTD Dec 2018	NC Retail Jurisdictional Amount	Lead \ Lag Days		Weighted Amount
	1	**OPERATING REVENUES:**						
	2							
	3							
Calc	4	Service Lag				15.21	A	
	5	Billing Lag						
1	6	Total Retail Sales & Billing Lag		(4,156,399,663)	(3,563,165,280)	1.66	A	
	7	Revenue - REPS		(24,719,022)	(24,719,022)			
	8	Unbilled Revenue	0440.99, 0442.19, 0442.29, 0444.99, 0445.09	13,507,473	12,096,317			
	9							
2	10	Collection Lag				25.01	A	
	11							
	12	Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17)		(4,167,611,212)	(3,575,787,985)	41.88		(149,748,041,162)
	13							
3	14	Total Revenue Lag Sales for Resale		(1,511,358,381)	(134,915,331)	33.73	A	(4,550,694,117)
	15	Provisions For Rate Refunds	0449	118,958,671	104,545,765	41.88	B	4,378,202,395
	16	Total Sales of Electricity (L12 through L14)		(5,560,010,922)	(3,606,157,551)	41.57		(149,920,532,884)
	17							
	18	Other Revenues:						
	19	Forfeited Discounts	0450100, 0450200	(8,582,371)	(7,663,772)	72.30	A	(554,090,707)
4c	20	Miscellaneous Revenues	0451100	(6,165,627)	(5,505,700)	76.00		(418,433,189)
4d	21	RENT - (454) - DIST PLT REL		(5,124,157)	(4,465,630)	41.63		(185,904,174)
4d	22	RENT - (454) - DIST POLE RENTAL REV		(12,960,572)	(10,901,069)	182.00		(1,983,994,633)
4d	23	RENT - (454) - TRANS PLT REL		(639,579)	(381,636)	41.63		(15,887,522)
4d	24	RENT - (454) - ADD FAC - WHLS		(2,806,145)	0	0.00		-
4d	25	RENT - (454) - ADD FAC - RET X LIGHTING		(5,162,072)	(4,617,085)	41.63		(192,209,244)
4d	26	RENT - (454) - ADD FAC - LIGHTING		(4,184,534)	(3,848,777)	41.63		(160,224,580)
4d	27	RENT - (454) - OTHER		(5,086,652)	(3,412,883)	68.21		(232,798,642)
	28	OTHER ELEC REV (456) - PROD PLT REL		(1,924,556)	(1,184,137)	41.88		(49,589,686)
	29	OTHER ELEC REV (456) - TRANS REL		(10,403,096)	(6,207,517)	41.88		(259,960,449)
	30	OTHER ELEC REV (456) - GEN PLT REL		0	0	41.88		-
	31	OTHER ELEC REV (456) - WH D/A		(55,825,581)	0	41.88		-
	32	OTHER ELEC REV (456) - OTHER		(548,940)	(368,310)	41.88		(15,424,225)
	33	OTHER ELEC REV (456) - REPS		(1,114,245)	(1,114,245)	41.88		(46,662,737)
	34	OTHER ELEC REV (456) - OTHER ENERGY		0	0	41.88		-
	35	OTHER ELEC REV (456) - DIST PLT REL	0456630	(1,611,605)	(1,404,491)	41.88		(58,817,730)
	36	REV - OTHER NC RETAIL SPECIFIC		(270,645)	(270,645)	41.88		(11,334,162)
	37	Total Other Revenues (L19 through L36)		(122,410,378)	(51,345,897)	81.51		(4,185,331,681)
	38							-
	39	**Utility Oper Revenues (L16 + L37)**		(5,682,421,300)	(3,657,503,448)	42.13		(154,105,864,564)
	40	ELECTRIC OPERATING REVENUE		5,682,421,300	3,657,503,448			
	41							
	42	**OPERATION AND MAINTENANCE EXPENSE:**						
	43							
5 + 6	44	**Fuel Used in Electric Generation**						
	45	OM Prod Energy - Fuel		1,410,621,869	863,120,481	28.49	A	24,588,906,214
	46	RECS Consumption Expense		18,521,748	18,521,748	28.49	A	527,654,628
	47	**Fuel Used in Elec Gen (HFM Greenbook I/S)**	F_FUEL_USED_ELEC_GEN	**1,429,143,617**	**881,642,228**	**28.49**		**25,116,560,842**
7	48							
7	49	OM PROD PURCHASES - CAPACITY COST		109,348,837	67,279,932	30.29	A	2,037,909,147
	50	OM PROD PURCHASES - ENERGY COST		597,919,200	365,384,360	30.29	A	11,067,492,256
	51	OM DEFERRED FUEL EXPENSE	0557980	(316,590,958)	(273,901,174)	28.49	C	(7,803,001,349)
	52	**Purchased Power (Acct 555) + Def Fuel (Acct 557)**	0555XXX	**390,677,079**	**158,763,118**	**33.40**		**5,302,400,054**
	53							
	54	**Total Other O&M Excluding Fuel and Purchased Power**						
9	55							
	56	Total Labor Expense		649,874,113	430,294,724	37.07	A	15,951,025,410
8	57							
	58	Pension and Benefits	0926XXX	115,350,507	76,270,687	13.97	A	1,065,501,492
10	59							
	60	Regulatory Commission Expense	0928000	8,592,296	7,037,696	93.25	A	656,265,126
11	61							
	62	Property Insurance	0924XXX	(774,442)	(525,984)	(222.30)	A	116,926,247
15	63							
	64	Injuries & Damages - Workman's Compensation	0925980	290,241	197,125	0.00	A	-
	65							
	66	Uncollectible Accounts	0904000, 0904001	10,008,548	8,937,301	0.00	A	-
	67							
	68	Remaining Other Oper & Maint Expense		763,377,394	528,607,218	40.52	D	21,421,632,363
	69							
	70	Total O&M Excl. Fuel and Purch. Power		1,546,718,656	1,050,818,766	37.32		39,211,350,637
	71							
	72	**Total Operation and Maintenance Expense (L47 + L52 + L70)**		**3,366,539,352**	**2,091,224,112**	**33.30**		**69,630,311,534**
	73							
	74	Total Depreciation & Amortization & Property Loss		1,060,260,424	669,787,484	0.00	A	-
	75							
	76	**Taxes Other Than Income Taxes**						
	77	Payroll Taxes		39,721,091	26,288,326	48.41	A	1,272,617,860
9	78	Property Tax		101,157,752	68,132,745	186.50		12,706,756,958
13	79	FED HEAVY VEHICLE USE TAX		61,024	48,458	0.00		-
	80	ELECTRIC EXCISE TAX - SC		2,222,093	0	0.00		-
	81	PRIVILEGE TAX		16,355,581	12,243,595	(11.97)		(146,555,834)
13	82	MISC TAX - NC		-6,034,064	-4,517,029	60.00	E	(271,021,743)
	83	MISC TAX - SC & OTHER STATES		-165	949	129.46	A	122,893
	84	PUC LICENSE TAX - SC		-121,100	0	0.00	A	-
	85	Taxes Other Than Income Taxes		153,362,212	102,197,044	132.70		13,561,920,134
16	86							
	87	Total Interest on Customer Deposits		8,642,928	7,970,989	137.50	A	1,096,011,021
14	88							
14	89	Federal Income Tax		(66,292,963)	(49,091,019)	44.75	A	(2,196,823,118)
	90	State Income Tax		(3,938,471)	(2,916,502)	44.75		(130,513,463)
	91	Income Tax - Deferred		220,852,977	164,993,723	0.00		-
	92	Net Income Taxes		150,621,543	112,986,202	(20.60)		(2,327,336,581)
	93							
	94	Investment of Tax Credit Adj Net	04114XX	(3,355,660)	(2,133,914)	0.00	A	-
	95							
	96	**Total Utility Operating Expenses (L72 + L74 + L85 + L87 + L92 + L94)**		4,736,070,798	2,982,031,917	27.48		81,960,906,108
	97							
	98	Interest Expense for Electric Operations		315,465,770	211,661,368	87.70	F	18,562,553,881
	99	Income for Equity Return (L100 - L198)		630,884,732	463,810,163	0.00	A	-
	100	Net Operating Income		946,350,502	675,471,531	27.48		18,562,553,881
	101							
	102	**Total Requirements (L96 + L100)**		5,682,421,300	3,657,503,448	27.48		100,523,459,988
	103							
	104							
	105	**Cash Working Capital Related to NC Sales Tax**		4,759,823 **G**				

Tickmark Legend

A	Lead/lag days was obtained from Lead/Lag study performed by Ernst & Young. See the Appendix in the Duke Lead Lag Report - DEP file.
B	Revenue refund will be returned through another mechanism; number set to Revenue Lag Days to eliminate effect on Cash Working Capital.
C	Lead/lag days for fuel is being used for this line item to faciliate elimination of this item with the adjustments to cash working capital being proposed in this rate case.
D	Remaining O&M for 2018 includes both nuclear fees and other O&M lines from the 2017 lead/lag study. Lead/lag days reflected is the weighted average of the amounts for those line items from the 2017 study.
E	This expense category is a new breakout for 2018. Lead/lag days was determined based on review of activity for 2018. A majority of the balance is related to a refund which was accrued in March and received in May. As such, a 60 day lag seems reasonable.
F	See 2017 Interest Lead Days tab for calculation.
G	Cash Working Capital Related to NC Sales Tax for 2018 was calculated on Schedule 17.

Duke Energy Progress, LLC | NC-3400
Docket No. E-2, Sub 1219 | Second Settlement
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

Detailed Narrative Explanation of Adjustment

This pro forma adjusts depreciation expense and income taxes for the amortization of deferred costs related to Asheville Combined Cycle. The Company is seeking a deferral of depreciation, property taxes, incremental O&M and return associated with the Asheville Combined Cycle from the date the plant is estimated to go into operation, December 2019, until rates are effective in September 2020.

The impact to operating income was determined as follows:

The impact to depreciation expense reflects an annual level of amortization of deferred costs related to Asheville Combined Cycle, including a return on investment. Deferred costs are being amortized over a three year period.

The impact to income taxes is determined by multiplying taxable income by the statutory tax rate.

The impact to rate base was determined as follows:

The impact to working capital is determined by including the regulatory asset balance in rate base and offsetting it with one year of amortization. In addition, the asset is offset by associated ADIT.

December Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through December 2019.
Updated NC-3405 for the estimated amount to go in service through February 2020.

January Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through January 2019.
Updated NC-3405 for the estimated amount to go in service through February 2020.

February Update

Updated NC-3403, NC-3404 and NC-3405 for actuals through February 2020; updated NC-3402 and NC-3403 to exclude O&M from Asheville CC deferral; NC-3406 updated to include the actual level of inventory on hand at Asheville CC when it became operational (01/31/2020)

Rebuttal

Updated NC-3406 after discussions with PS on O&M annualization methodology for new plant.
Updated NC-3403 to correct ADIT formula for March 2020.
Updated NC-3405 for Other Production Plant in service balance due to updated April forecast.
Liquidated damages were removed from the calculation as no settlement is expected near term.

Settlement

Adjusted NC-3401 to account for the Public Staff/Company settlement of the Asheville production displacement O&M and to remove Asheville deferral and associated ADIT from rate base (annuity factor method);
Added NC-3402-1 to account for the amortization calculated on the annuity factor method

Second Settlement

Reflect changes in ROE and debt rate

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3400
Second Settlement

Line No.	Description	Source	Total NC Retail			
1			Second Settlement	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue		$ -	$ -	$ -	$ -
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation		-	-	-	-
9	Purchased power		-	-	-	-
10	Other operation and maintenance expense	NC-3401	(1,459)	(1,459)	6,109	(7,568)
11	Depreciation and amortization	NC-3401	8,897	8,970	13,594	(4,696)
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes	NC-3401	(1,723)	(1,740)	(4,565)	2,842
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	5,715	5,771	15,138	(9,423)
18						
19	Operating income	L4 - L17	$ (5,715)	$ (5,771)	$ (15,138)	$ 9,423
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					
24						
25						
26	**Pro Formas Impacting Rate Base Line Items**					
27						
28	Electric plant in service		$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-
31						
32	Add:					
33	Materials and supplies	NC-3401	3,488	3,488	3,735	(248)
34	Working capital investment	NC-3401	-	-	27,188	(27,188)
35						
36						
37	Less:					
38	Accumulated deferred taxes	NC-3401	-	-	(6,299)	6,299
39	Operating reserves		-	-	-	-
40						
41						
42	Construction work in progress		-	-	-	-
43						
44	Total impact to rate base	Sum L30 through L42	$ 3,488	$ 3,488	$ 24,624	$ (21,136)
45						
46	Note:					
47	Rate Base: positive number increases rate base / negative number decreases rate base					

Duke Energy Progress, LLC | NC-3401
Docket No. E-2, Sub 1219 | Second Settlement
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description		Total NC Retail	
1	Impact to Income Statement Line Items			
2	Average Annual Combined Cycle O&M	$	2,613	[1]
3	Production displacement adjustment per Public Staff		(4,072)	
4	Impact to O&M (L2)	$	(1,459)	
5				
6	Annual levelized amortization expense	$	8,897	[2]
7	Impact to depreciation and amortization (L6)	$	8,897	
8				
9	Statutory tax rate		23.1693%	[3]
10	Impact to income taxes (-(L4+ L7) x L9)	$	(1,723)	
11				
12	Impact to operating income (-L4 - L7 -L10)	$	(5,715)	
13				
14				
15	Impact to Rate Base Line Items			
16	Estimated level of inventory at Asheville CC at operational date	$	3,488	[1]
17	Impact to materials and supplies (L16)	$	3,488	
18				
19	Regulatory asset at Sep 1, 2020 (L6)	$	-	
20	Less first year of amortization (-L7)		-	
21	Impact to working capital investment (Sum L19 through L20)	$	-	
22				
23	Deferred tax rate		23.1693%	[3]
24	Impact to accumulated deferred income tax (-L21 x L23)	$	-	
25				
26	Impact to rate base (L17 + L21 + L24)	$	3,488	

[1] NC-3406 Asheville Combined Cycle - Average O&M and Inventory Balances
[2] NC-3402-1 Asheville Combined Cycle Amortization Expense
[3] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3402
Second Settlement

Expected Balance of Deferred Costs at September 1, 2020 - Asheville Combined Cycle - NC Retail

Line No.	Description	Other Production [1]	Transmission [2]	Total NC Retail	
1	Deferred Cost of Capital	$ 16,335	$ 475	$ 16,809	[1]
2	Deferred Depreciation	11,062	94	11,156	[1]
3	Deferred O&M Expense	1,770	-	1,770	[1]
4	Deferred Property Tax Expense	1,040	20	1,060	[1]
5	After-Tax Return on Deferred Expenses	668	16	684	[1]
6	Total expected deferral balance in Regulatory Asset (Sum L1 through L5)	$ 30,874	$ 605	$ 31,479	

[1] NC-3403 - Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail, Line 13

[2] NC-3404 - Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail, Line 13

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

NC-3402-1
Settlement

Asheville Combined Cycle Amortization Expense

Line No.	Item	Amount	
	Annuity Factor		
1	Amortization period recommended by Public Staff in years	4	
2	Payment per period	1	
3	After tax rate of return (L18)	6.48%	
4	Present value of 1 dollar over number of years with 1 payment per year	3.4270	
5	1 plus (interest rate divided by two)	1.0324	
6	Annuity factor (L4 x L5)	3.5380	
7	Deferred costs	$ 31,479	1/
8	Annuity factor (L6)	3.5380	
9	Annual levelized amortization expense (L7 / L8)	$8,897	

		Capital Structure (a)		Cost Rates (b)		Overall Rate of Return (c)	Net of Tax Rate (d)
	After Tax Rate of Return		2/		2/		
12	Long-term debt	48.00%		4.04%		1.94%	1.49%
13	Common equity	52.00%		9.60%		4.99%	4.99%
14	Total	100.00%				6.93%	6.48%

1 NC-3402 - Expected Balance of Deferred Costs at 9/1/2020 - Asheville CC - NC Retail
2 Smith Settlement Exhibit 1 - Page 2

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3403
Second Settlement

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail

Line No.	Description	Plant Bal [1]	ADIT Bal [2]	Average Inventory Bal [3]	Accumulated Depreciation	Remove CWIP in Rate Base [4]	Rate Base		Deferred Cost of Capital 2019	Deferred Cost of Capital 2020	Deferred Cost of Capital Total	Deferred Depreciation 2019	Deferred Depreciation 2020	Deferred Depreciation Total	Deferred O&M Expense [5] 2019	Deferred O&M Expense [5] 2020	Deferred O&M Expense [5] Total
1																	
2	Plant in Service Dec 2019 costs (U1 12/27/19)	302,260	(28,013)	3,488	-	(102,930)	174,805		162		162	-		-	28		28
3	Jan 2020 costs	347,271	(32,184)	3,488	(1,035)	(102,930)	214,610			1,546	1,546		1,035	1,035		218	218
4	Feb 2020 costs	347,271	(32,184)	3,488	(2,223)	(102,930)	213,421			1,537	1,537		1,189	1,189		218	218
5	Mar 2020 costs	347,271	(32,184)	3,488	(3,412)	(102,930)	212,233			1,529	1,529		1,189	1,189		218	218
6	Apr 2020 costs	471,960	(43,740)	3,488	(4,600)	(102,930)	324,177			2,335	2,335		1,189	1,189		218	218
7	May 2020 costs	471,960	(43,740)	3,488	(6,216)	(102,930)	322,561			2,324	2,324		1,615	1,615		218	218
8	Jun 2020 costs	471,960	(43,740)	3,488	(7,831)	(102,930)	320,946			2,312	2,312		1,615	1,615		218	218
9	Jul 2020 costs	471,960	(43,740)	3,488	(9,446)	(102,930)	319,331			2,300	2,300		1,615	1,615		218	218
10	Aug 2020 costs	471,960	(43,740)	3,488	(11,062)	(102,930)	317,715			2,289	2,289		1,615	1,615		218	218
11																	
12	Total Costs Through Aug 31,2020								162	16,172	16,335	-	11,062	11,062	28	1,742	1,770
13																	
14								After-Tax	Tax		Pre-Tax						
15	Cost of Capital [8]:							Equity	Rate		Equity						
16	Assumed Capital Structure:																
17	Long-Term Debt							48.00%									
18	Common Equity							52.00%									
19																	
20	Cost Rates:																
21	Long-Term Debt							4.05%			4.0500%						
22	Common Equity							9.90%	23.1693%		12.8855%						
23								13.95%			16.9355%						
24	Cost Components:																
25	Long-Term Debt							1.9440%			1.9440%	22.4884%					
26	Common Equity							5.1480%	23.1693%		6.7004%	77.5116%					
27	Rate							7.0920%			8.6444%	100.0000%					
28																	
29	Depreciation Rates:																
30	Book depreciation rate - Other Production - Asheville CC							4.11%	[10]								
31	Average Property Tax Rate							0.3626%	[9]								
32	Deferred tax rate								23.1693% [7]								

NC-3403
Page 1 of 2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Other Production - NC Retail

Line No.	Description	Deferred Property Tax Expense [6] 2019	2020	Total	After-Tax Return on Deferred Expenses 2019	2020	Total	Deferred Total 2019	2020	Total
1										
2	Plant in Service Dec 2019 costs (U1 12/27/	12		12	0		0	202		202
3	Jan 2020 costs		105	105		10	10		2,913	2,913
4	Feb 2020 costs		105	105		27	27		3,076	3,076
5	Mar 2020 costs		105	105		46	46		3,086	3,086
6	Apr 2020 costs		143	143		66	66		3,951	3,951
7	May 2020 costs		143	143		91	91		4,390	4,390
8	Jun 2020 costs		143	143		117	117		4,404	4,404
9	Jul 2020 costs		143	143		143	143		4,419	4,419
10	Aug 2020 costs		143	143		169	169		4,433	4,433
11										
12	Total Costs Through Aug 31,2020	12	1,028	1,040	0	668	668	202	30,672	30,874
13										
14										
15	Cost of Capital [8]:									
16	Assumed Capital Structure:									
17	Long-Term Debt									
18	Common Equity									
19										
20	Cost Rates:									
21	Long-Term Debt									
22	Common Equity									
23										
24	Cost Components:									
25	Long-Term Debt									
26	Common Equity									
27	Rate									
28										
29	Depreciation Rates:									
30	Book depreciation rate - Other Production - Asheville CC									
31	Average Property Tax Rate									
32	Deferred tax rate									

[1] NC-3405 - Asheville Combined Cycle - Plant in Service - Costs by Month
[2] Other Production additions that qualify for bonus depreciation multiplied by 40% and then the deferred tax rate on Line 32
[3] NC-3406 - Asheville Combined Cycle - Average O&M and Inventory Balances, Line 13
[4] NC-1011 - Adjust for Asheville base load CWIP - Docket No. E-2, Sub 1142
[5] O&M during the deferral period was removed from the calculation for February supplemental filing.
[6] Plant Balance column divided by 12 months multiplied by Line 31.
[7] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[8] Cost of capital rates from Docket No. E-2, Sub 1142
[9] NC-0901 - Annualize property taxes on year end plant balances - Average property tax rate-Combined NC and SC
[10] Asheville CC composite depreciation rate provided by Asset Accounting
[11] Adjusted to reflect a rates effective date of Sep 1, 2020

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail

Line No.	Description	Plant Bal [1]	ADIT Bal [2]	Average Inventory Bal [3]	Accumulated Depreciation	Remove CWIP in Rate Base	Rate Base	Deferred Cost of Capital 2019	Deferred Cost of Capital 2020	Deferred Cost of Capital Total	Deferred Depreciation 2019	Deferred Depreciation 2020	Deferred Depreciation Total	Deferred O&M Expense [4] 2019	Deferred O&M Expense [4] 2020	Deferred O&M Expense [4] Total
1																
2	Plant in Service Dec 2019 costs	7,422	(67)	-	-	-	7,354	53		53			-	-		-
3	Jan 2020 costs	7,431	(67)	-	(12)	-	7,351		53	53		12	12		-	-
4	Feb 2020 costs	7,436	(67)	-	(24)	-	7,345		53	53		12	12		-	-
5	Mar 2020 costs	7,436	(67)	-	(35)	-	7,333		53	53		12	12		-	-
6	Apr 2020 costs	7,436	(67)	-	(47)	-	7,322		53	53		12	12		-	-
7	May 2020 costs	7,436	(67)	-	(59)	-	7,310		53	53		12	12		-	-
8	Jun 2020 costs	7,436	(67)	-	(71)	-	7,298		53	53		12	12		-	-
9	Jul 2020 costs	7,436	(67)	-	(82)	-	7,286		52	52		12	12		-	-
10	Aug 2020 costs	7,436	(67)	-	(94)	-	7,275		52	52		12	12		-	-
11																
12	Total Costs Through Aug 31,2020							53	422	475	-	94	94	-	-	-

Line No.	Description	After-Tax Equity	Tax Rate	Pre-Tax Equity	
13					
14					
15	Cost of Capital [7]:				
16	Assumed Capital Structure:				
17	Long-Term Debt	48.00%			
18	Common Equity	52.00%			
19					
20	Cost Rates:				
21	Long-Term Debt	4.05%		4.0500%	
22	Common Equity	9.90%	23.1693%	12.8855%	
23		13.95%		16.9355%	
24	Cost Components:				
25	Long-Term Debt	1.9440%		1.9440%	22.4884%
26	Common Equity	5.1480%	23.1693%	6.7004%	77.5116%
27	Rate	7.0920%		8.6444%	100.0000%
28					
29	Depreciation Rates:				
30	Book depreciation rate - Transmission	1.90%	[9]		
31	Average Property Tax Rate	0.3626%	[8]		
32	Deferred tax rate		23.1693% [6]		

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

Asheville Combined Cycle Deferral Calculation -Defer From In Service Date to Rates Effective Date - Transmission - NC Retail

Line		Deferred Property Tax Expense [5]			After-Tax Return on Deferred Expenses			Deferred Total		
No.	Description	2019	2020	Total	2019	2020	Total	2019	2020	Total
1										
2	Plant in Service Dec 2019 costs	2		2	0		0	55		55
3	Jan 2020 costs		2	2		1	1		67	67
4	Feb 2020 costs		2	2		1	1		68	68
5	Mar 2020 costs		2	2		1	1		68	68
6	Apr 2020 costs		2	2		2	2		68	68
7	May 2020 costs		2	2		2	2		69	69
8	Jun 2020 costs		2	2		3	3		69	69
9	Jul 2020 costs		2	2		3	3		69	69
10	Aug 2020 costs		2	2		3	3		70	70
11										
12	Total Costs Through Aug 31,2020	2	18	20	0	15	16	55	549	605
13										
14										
15	Cost of Capital [7]:									
16	Assumed Capital Structure:									
17	Long-Term Debt									
18	Common Equity									
19										
20	Cost Rates:									
21	Long-Term Debt									
22	Common Equity									
23										
24	Cost Components:									
25	Long-Term Debt									
26	Common Equity									
27	Rate									
28										
29	Depreciation Rates:									
30	Book depreciation rate - Transmission									
31	Average Property Tax Rate									
32	Deferred tax rate									

[1] NC-3405 - Asheville Combined Cycle - Plant in Service - Costs by Month
[2] Transmission additions that qualify for bonus depreciation multiplied by 40% and then the deferred tax rate on Line 32
[3] Not estimating incremental inventory for the transmission additions.
[4] Not estimating incremental O&M for the transmission additions.
[5] Plant Balance column divided by 12 months multiplied by Line 31.
[6] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[7] Cost of capital rates from Docket No. E-2, Sub 1142
[8] NC-0901 - Annualize property taxes on year end plant balances - Average property tax rate-Combined NC and SC
[9] NC-0802 - Adjustment of Depreciation Expense to Reflect Plant in Service for 12 Months Ended December 31, 2018, Transmission Other depr rate
[10] Adjusted to reflect a rates effective date of Sep 1, 2020

NC-3404
Page 2 of 2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3405
Second Settlement

Asheville Combined Cycle - Plant in Service - Costs by Month

Line No.	Year	Month	System Other Production		System Transmission		NC Retail Allocation		NC Retail Allocation		NC Retail Other Production	NC Retail Transmission
1												
2	2019	12	491,258	[1]	12,438	[1]	61.5278%	[2]	59.6699%	[3]	302,260	7,422
3	2020	1	564,413	[1]	12,453	[1]	61.5278%	[2]	59.6699%	[3]	347,271	7,431
4	2020	2	564,413	[1]	12,462	[1]	61.5278%	[2]	59.6699%	[3]	347,271	7,436
5	2020	3	564,413	[1]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	347,271	7,436
6	2020	4	767,067	[4][5]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
7	2020	5	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
8	2020	6	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
9	2020	7	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
10	2020	8	767,067	[4]	12,462	[4]	61.5278%	[2]	59.6699%	[3]	471,960	7,436
11	Total Project Cost		$ 767,067		$ 12,462						$ 471,960	$ 7,436

[1] Estimated amounts provided by Asheville Combined Cycle Project Management
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - DTALL
[4] Forecasted amount updated as of rebuttal is based on actual amounts in service through March 31, 2020 and the expected plant impacts of $202,654 estimated to close to plant in service in April 2020 after Unit 8 was placed in operation on April 5, 2020. The amounts no longer include the offset of liquidated damages due to lack of settlement or recovery of those dollars.

[5] Adjusted the Asheville CC project costs to exclude approximately $208,000 of Task Force consulting expenses noted in PS DR 125-5 from rate base

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Amortize deferred cost balance related to Asheville Combined Cycle
For the test period ended December 31, 2018

NC-3406
Second Settlement

Asheville Combined Cycle - Average O&M and Inventory Balances

Line No.	Account	2017 HF Lee CC	2018 HF Lee CC	2019 HF Lee CC	2017 Sutton CC	2018 Sutton CC	2019 Sutton CC	2019 WS Lee CC	Total	Asheville CC Estimated O&M [1]	NC Retail Allocation		Total NC Retail
1	0546000 - Suprvsn and Enginring - Ct Oper	$ 92,198	$ 100,617	$ 100,007	$ 232,804	$ 179,490	$ 110,939	$ 457,215	$ 1,273,270	$ 141,527	61.5278%	[2]	$ 87,078
2	0548100 - Generation Expenses - Other Ct	119,879	116,758	132,531	148,997	153,474	173,147	61,930	906,716	100,783	61.5278%	[2]	62,010
3	0548200 - Prime Movers - Generators - Ct	65,911	99,916	10,918	502	11,945	(5,327)	103,633	287,498	31,956	61.5278%	[2]	19,662
4	0549000 - Misc - Power Generation Expense	1,381,785	1,743,750	1,317,717	1,315,850	1,015,091	886,985	1,937,135	9,598,313	1,066,872	61.5278%	[2]	656,423
5	0551000 - Suprvsn and Enginring - Ct Maint	177,498	184,128	116,985	230,797	165,793	132,238	180,865	1,188,304	132,082	61.1093%	[3]	80,715
6	0552000 - Maintenance of Structures - Ct	1,547,782	906,408	1,376,132	935,485	1,046,433	1,044,128	1,586,405	8,442,773	938,431	61.1093%	[3]	573,469
7	0553000 - Maint - Gentg and Elect Equip - Ct	1,388,188	1,451,269	1,728,401	1,075,199	888,315	1,130,820	2,184,052	9,846,244	1,094,430	61.1093%	[3]	668,799
8	0554000 - Misc Power Generation Plant - Ct	713,674	917,999	566,782	861,489	845,555	1,080,399	1,850,331	6,836,229	759,861	61.1093%	[3]	464,346
9	0570100 - Maint Stat Equip - Other_Trans	-	1,136	-	-	-	-	5,860	6,996	778	59.6699%	[4]	464
10	Total O&M	$ 5,486,914	$ 5,521,982	$ 5,349,473	$ 4,801,124	$ 4,306,096	$ 4,553,328	$ 8,367,427	$ 38,386,344	$ 4,266,720			$ 2,612,965
11													
12	MW Capacity (Per Duke Energy website)	920	920	920	625	625	625	750		588			
13													
14	Dollars per MW Capacity	$5,964	$6,002	$5,815	$7,682	$6,890	$7,285	$11,157		$4,266,720			
15	Average per MW capacity							$7,256					
16													
17													
18	Actual level of inventory for Asheville CC at the time the plant becomes operational (01/31/2020)									$5,135,089 [5]	67.9178%	[6]	$ 3,487,639

[1] Direct Operation and Maintenance expenses, excluding outage costs, provided by Regulated Utility Finance
[2] NC Retail Allocation Factor - DPALL
[3] NC Retail Allocation Factor - E1ALL
[4] NC Retail Allocation Factor - DTALL
[5] Estimated Inventory level provided by Supply Chain/Asset Accounting
[6] NC Retail Allocation Factor - PTDG
[7] Per www.duke-energy.com

Duke Energy Progress, LLC | NC-3800
Docket No. E-2, Sub 1219 | Narrative
Settlement adjustment to remove certain items | Second Settlement
For the test period ended December 31, 2018

E-1 Item 10 Adjustments Requirement
Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

Supplemental Rebuttal Update
Adjustment to remove certain expenses agreed to in the partial settlement and stipulation.

Second Settlement
Adjustment to reduce deommissioning expenses to settlement

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3800
Second Settlement

Line No.	Description	Source	Total NC Retail: Second Settlement	Partial Settlement	Application	Change
1			Second Settlement	Partial Settlement	Application	Change
2	**Pro Formas Impacting Income Statement Line Items**					
3						
4	Electric operating revenue					
5						
6	Electric operating expenses:					
7	Operation and maintenance					
8	Fuel used in electric generation		-	-	-	-
9	Purchased power		-	-	-	-
10	Other operation and maintenance expense		(2,834)	(2,834)	-	(2,834)
11	Depreciation and amortization		$ (8,700)	-	-	(8,700)
12	General taxes		-	-	-	-
13	Interest on customer deposits		-	-	-	-
14	Income taxes		2,672	657	-	2,672
15	Amortization of investment tax credit		-	-	-	-
16						
17	Total electric operating expenses	Sum L8 through L15	(8,861)	(2,177)	-	(8,861)
18						
19	Operating income	L4 - L17	$ 8,861	$ 2,177	$ -	$ 8,861
20						
21	Notes:					
22	Revenue: positive number increases revenue / negative number decreases revenue					
23	Expense: positive number increases expense / negative number decreases expense					
24						
25						
26	**Pro Formas Impacting Rate Base Line Items**					
27						
28	Electric plant in service		$ -	$ -	$ -	$ -
29	Accumulated depreciation and amortization		-	-	-	-
30	Electric plant in service, net	Sum L28 through L29	-	-	-	-
31						
32	Add:					
33	Materials and supplies		-	-	-	-
34	Working capital investment		-	-	-	-
35						
36						
37	Less:					
38	Accumulated deferred taxes		-	-	-	-
39	Operating reserves		-	-	-	-
40						
41						
42	Construction work in progress		-	-	-	-
43						
44	Total impact to rate base	Sum L30 through L42	$ -	$ -	$ -	$ -
45						
46	Note:					
47	Rate Base: positive number increases rate base / negative number decreases rate base					

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(Dollars in thousands)

NC-3801
Second Settlement

Line No.	Description	Total Carolinas	NC Retail Allocation	Total NC Retail
1	Impact to Income Statement Line Items:			
2	Remove O&M related to Sponsorships	$ (38) [1]	61.528% [6]	$ (23)
3	Remove O&M related to Outside Services	(52) [2]	61.528% [6]	(32)
4	Remove O&M related to Lobbying	(2,429) [3]	61.528% [6]	(1,494)
5	Remove O&M related to BOD	(2,086) [4]	61.528% [6]	(1,283)
6	Impact to other operation and maintenance expense (Sum L2 through L5)	$ (4,606)		$ (2,834)
7				
8	Adjust nuclear decommissioning expense			$ (8,700)
9	Impact to Depreciation and amortization expense (L8)			
10				
8	Taxable income (-L6)			$ 11,534
9	Statutory tax rate			23.1693% [5]
10	Impact to income taxes (L8 x L9)			$ 2,672
11				
12	Impact to operating income (L8 - L10)			$ 8,861

[1] NC-3802 - Settlement adjustment to remove certain Sponsorships cost
[2] NC-3805 - Settlement adjustment to remove certain Outside Services
[3] NC-3803 - Settlement adjustment to remove amounts defined by Public Staff as Lobbying
[4] NC-3804 - Settlement adjustment to remove certain BOD expenses
[5] NC-0104 - 2018 Calculation of Tax Rates - Statutory Tax Rate, Line 10
[6] DPALL

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(in Thousands)

NC-3802
Second Settlement

Settlement adjustment to remove certain Sponsorships cost

Line No	Item	Amount		
1	Remove sponsorships and donations related to chambers of commerce	$	(37)	
2	NC retail percentage		61.528%	[1]
3	NC Retail Adjustment to Other O&M	$	(23)	
4				
5	Taxable income (-L3)	$	23	
6	Statutory tax rate		23.1693%	
7	Impact to income taxes (L13 x L14)	$	5	

[1] DPALL

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(in Thousands)

NC-3803
Second Settlement

Settlement adjustment to remove amounts defined by Public Staff as Lobbyinc

Line No.	Item	Amount	
1	Remove Stakeholder Engagement O&M charges related to lobbying	($1,343)	[1]
2	Remove State Government Affairs O&M charges related to lobbying	(94)	[1]
3	Remove Federal Affairs O&M charges related to lobbying	(992)	[1]
4	Total lobbying costs to be removed from O&M expense (L1 + L2 + L3)	(2,429)	
5			
6	NC retail percentage	61.528%	[2]
7	Public Staff adjustment to remove lobbying expense (L4 x L5)	($1,494)	
8			
9	Taxable income (-L3)	$ 1,494	
10	Statutory tax rate	23.1693%	
11	Impact to income taxes (L13 x L14)	$ 346	

1/ Based on Company response to Public Staff Data Request No. 31, Items 3 and 4.
2/ DPALL

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(in Thousands)

NC-3804
Second Settlement

Settlement adjustment to remove certain BOD expenses

Line No.	Item	Amount	
1	Total Board of Directors (BOD) cash compensation	$ 421	1/
2	Percentage of exclusion per Settlement	50%	2/
3	Adjustment to BOD compensation (-L1 x L2)	$ (210)	
4	BOD insurance charged to DEP	$ 3,514	3/
5	Percentage of exclusion per Settlement	50%	2/
6	Adjustment to BOD insurance (-L4 x L5)	$ (1,757)	
7	BOD and executive members expenses allocated to DEP	$ 237	4/
8	Percentage of exclusion per Settlement	50%	2/
9	Adjustment to BOD and executive members expenses (-L7 x L8)	$ (119)	
10	Total adjustment to BOD compensation and expenses (L3 + L6 + L9)	$ (2,086)	
11	NC retail percentage	61.5278%	5/
12	Adjustment to BOD expenses - NC retail (L10 x L11)	$ (1,283)	
13	Taxable income (-L12)	$ 1,283	
14	Statutory tax rate	23.1693%	
15	Impact to income taxes (L13 x L14)	$ 297	

1/ Amount from 2018 Proxy Statement page 30, allocated to DEP.
2/ Recommended by Public Staff.
3/ Company Response to Public Staff Data Request No. 71, Item 1.
4/ Company Response to Public Staff Data Request No. 72 , Item 2.
5/ DPALL

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(in Thousands)

NC-3805
Second Settlement

Settlement adjustment to remove certain Outside Services

Line No	Item		Amount
1	Remove outside services costs agreed upon	$	(52)
2	NC retail percentage		61.5278%
3	NC Retail Adjustment to Other O&M	$	(32)
4			
5	Taxable income (-L3)	$	32
6	Statutory tax rate		23.1693%
7	Impact to income taxes (L13 x L14)	$	7

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Settlement adjustment to remove certain items
For the test period ended December 31, 2018
(in Thousands)

NC-3806
Second Settlement

Settlement adjustment to adjust nuclear decommissioning expense

Line No	Item			Annual Expense	
1	Base rates			$ 16,537	[1]
2	Joint Agency Asset Rider			3,054	
3	Total Nuclear Decommissing Expense			$ 19,590	[2]
4					
5	Proposed % exclusion		25%		
6	Reduction to expense (L1 x -L5)	$	(4,134)		
7					
8	NC Retail Adjustment			$ (8,700)	
9					
10	Taxable income (-L6)			$ 8,700	
11	Statutory tax rate			23.1693%	
12	Impact to income taxes (L8 x L9)			2,016	
13					
14	Impact to operating income (-L6 - L10)			$ 6,684	

[1] Direct Testimony of Shana Angers, pg 6
[2] Annual NC Retail amount of nuclear decommissioning expense as approved in Docket No. E-2, Sub 1142

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust Rate Base for EDIT
For the test period ended December 31, 2018

NC-4000
Narrative
Second Settlement

E-1 Item 10 Adjustments Requirement

Provide the detail work papers showing calculations supporting all accounting, pro forma, end-of-period, and proposed rate adjustments in the rate application to revenue, expense, investment, and reserve accounts for the test year and a complete detailed narrative explanation of each adjustment, including the reason why each adjustment is required. Explain all components used in each calculation. Index each calculation to the accounting, pro forma, end-of-period, and proposed rate adjustment which it supports.

Detailed Narrative Explanation of Adjustment

Supplemental Rebuttal

As agreed with in settlement, this pro forma reflects an adjustment to rate base based on Public Staff levelized EDIT rider methodology.

Duke Energy Progress, LLC | NC-4000
Docket No. E-2, Sub 1219 | Second Settlement
Adjust Rate Base for EDIT
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	Source	NC Retail
1			Second Settlement
2	**Pro Formas Impacting Income Statement Line Items**		
3			
4	Electric operating revenue		$ -
5			
6	Electric operating expenses:		
7	Operation and maintenance		
8	Fuel used in electric generation		-
9	Purchased power		-
10	Other operation and maintenance expense		-
11	Depreciation and amortization		-
12	General taxes		-
13	Interest on customer deposits		-
14	EDIT Amortization		-
15	Income taxes		-
16	Amortization of investment tax credit		-
17			
18	Total electric operating expenses	Sum L8 through L15	-
19			
20	Operating income	L4 - L17	$ -
21			
22	Notes:		
23	Revenue: positive number increases revenue / negative number decreases revenue		
24	Expense: positive number increases expense / negative number decreases expense		
25			
26			
27	**Pro Formas Impacting Rate Base Line Items**		
28			
29	Electric plant in service		$ -
30	Accumulated depreciation and amortization		-
31	Electric plant in service, net	Sum L28 through L29	-
32			
33	Add:		
34	Materials and supplies		-
35	Working capital investment		-
36			
37			
38	Less:		
39	Accumulated deferred taxes		538,063
40	Operating reserves		-
41			
42			
43	Construction work in progress		-
44			
45	Total impact to rate base	Sum L30 through L42	$ 538,063
46			
47	Note:		
48	Rate Base: positive number increases rate base / negative number decreases rate base		

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Adjust Rate Base for EDIT
For the test period ended December 31, 2018

No.	Description	Amount	
1	Impact to Rate Base		
2	Adjust Rate Base for EDIT per Public Staff	538,063	[1]

[1] Per Dorgan Supplemental Exhibit 1, Schedule 2-1, Page 1 Line 16, column (b).

I/A

Smith Exhibit 2
Second Settlement

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Line No.	Description	NC RETAIL	Reference
1	Additional base revenue requirement	$ 408,933	Smith Second Settlement Exhibit 1
2	REVISED Annual EDIT Rider 1	7,381	Smith Exhibit 3
3	Annual EDIT Rider 2 - Year 1 giveback	(152,348)	Smith Second Settlement Exhibit 4
4	Regulatory Asset and Liability Rider	(2,091)	Smith Exhibit 5
5	Subtotal	(147,058)	Sum L3 - L17
6	Net Revenue Increase	$ 261,875	

I/A

DUKE ENERGY PROGRESS, LLC
Reconciliation of Revenue Requirement
DOCKET NO. E-2, SUB 1219 FOR THE TEST PERIOD ENDED DECEMBER 31, 2018
(Thousands of Dollars)

Smith Exhibit 3
Second Settlement

Line No.		Item		Amount
1	Revenue requirement increase per Company application			**585,961**
2	Revenue impact of Company adjustments through Settlement			(173,156)
3	Revenue impact of supplemental updates through May			25,406
4	Revenue impact of Second Supplemental 9.75 and 52/48			(48,774)
5	Revenue requirement increase per Company Second Supplemental Filing		**$**	**389,438**
6				
7	Updated Proformas:			
8	Ex 1	Adjust ROE from 9.75% to 9.6%		(10,508)
9	Ex 1	Adjust D/E Ratio from 52/48		-
10	Ex 1	Adjust Debt rate from 4.11% to 4.04%		(4,043)
11	NC0400	Annualize revenues for customer growth		(910)
12	NC1100	Amortize deferred environmental costs		(2,816)
13	NC0700	Adjust O&M for executive compensation		(26)
14	NC2200	Adjust synchronized interest expense		(2,243)
15	NC2300	Adjust cash working capital under present rates		(125)
16	NC2300	Adjust cash working capital under proposed rates		3,395
17	NC3400	Amortize deferred balance Asheville Combined Cycle		(73)
18	NC3800	Remove certain Settlement Items		(8,732)
19	NC4000	Adjust Rate Base for EDIT		45,575
20	Total Revenue impact of adjustments		$	19,495
21				
22	Revenue Requirement per Smith Exhibit 1 Second Settlement		**$**	**408,933**

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
North Carolina Retail Operations
Smith Second Settlement Exhibit 4
CALCULATION OF LEVELIZED FEDERAL PROVISIONAL EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Year 1 Revenue Requirement (a)		Year 2 Revenue Requirement (b)		Year 3 Revenue Requirement (b)		Year 4 Revenue Requirement (b)		Year 5 Revenue Requirement (b)		Total Revenue Requirement (c)
1	Annual EDIT used to offset interim rates	(211,591)	5/									
2	Monthly EDIT used to offset interim rates	(17,633)										
3	Estimated number of months of interim rates to compliance rates per NCUC Order	4.0	5/									
4	EDIT used to offset interim rates	(70,530)										
5	Return component	(11,629)										
6	Amortization component	(58,901)										
7	Preliminary NC retail Unprotected Federal EDIT regulatory liability	(403,750)	1/									
8	Reduction for amount flowed back during Interim Rate period (L6)	(58,901)										
9	Total NC retail Unprotected Federal EDIT regulatory liability to be amortized (L7 - L8)	(344,849)		(344,849)	1/	(344,849)	1/	(344,849)	1/	(344,849)	1/	
10	Annuity factor	4.2922	2/	4.2922	2/	4.2922	2/	4.2922	2/	4.2922	2/	
11	Levelized rider EDIT regulatory liability (L9 / L10)	(80,343)		(80,343)		(80,343)		(80,343)		(80,343)		($401,715)
12	One minus composite income tax rate	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%
13	Net operating income effect (L11 x L12)	(61,728)		(61,728)		(61,728)		(61,728)		(61,728)		(308,640)
14	Retention factor	0.765471	4/	0.765471	4/	0.765471	4/	0.765471	4/	0.765471	4/	0.765471
15	Levelized rider EDIT credit (L13 / L14)	($80,641)		($80,641)		($80,641)		($80,641)		($80,641)		($403,205)
16	Total NC retail NC State EDIT and Deferred Revenue regulatory liability to be amortized	$ (134,312)	1/	($134,312)	1/							
17	Annuity factor	1.8800	2/	1.8800	2/							
18	Levelized rider EDIT regulatory liability (L16 / L17)	(71,443)		(71,443)								($142,886)
19	One minus composite income tax rate	76.8307%	3/	76.8307%	3/							76.8307%
20	Net operating income effect (L18 x L19)	(54,890)		(54,890)								($109,780)
21	Retention factor	0.765471	4/	0.765471	4/							0.765471
22	Levelized rider EDIT credit (L20 / L21)	($71,707)		($71,707)								($143,415)

1/ Dorgan Supplemental Exhibit 1, Sch 2-1(b), Federal EDIT amounts from Line 2, NC EDIT and Deferred Revenue balances are from Lines 3 + 4.
2/ Calculation of Levelized Factors, Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Maness Stipulation Exhibit 1, Schedule 1-2, Line 14, Column (d).
5/ Will be trued up with actual months of interim rates and approved offset amount if different in compliance filing

I/A

Duke Energy Progress, LLC
DOCKET E-2 Sub 1219
NORTH CAROLINA RETAIL
Smith Second Settlement Exhibit 4
Calculation of Levelized Factors

Line No.	Item	Amount		Amount	
	Annuity Factor				
1	Number of years	5	1/	2	2/
2	Payment per period	1		1	
3	After tax rate of return (L9)	6.484%		6.484%	
4	Present value of 1 dollar over number of years with with 1 payment per year	4.1575		1.8210	
5	1 plus (interest rate divided by two)	1.0324		1.0324	
6	Annuity factor (L4 x L5)	4.2922		1.8800	

		Capital Structure (a)		Cost Rates (b)		Overall Rate of Return 4/ (c)	Net of Tax Rate (d)	
	After Tax Rate of Return							
7	Long-term debt	48.00%	3/	4.045%	3/	1.942%	1.492%	5/
8	Common equity	52.00%	3/	9.600%	3/	4.992%	4.992%	6/
9	Total	100.00%				6.934%	6.484%	
10	Statutory Tax Rate						23.17%	

1/ Unprotected EDIT amortization period as per settlement.
2/ NC EDIT and Defered Revenue amortization period per settlement
3/ Smith Second Settlement Exhibit 1
4/ Column (a) times Column (b).
5/ Column (c) times (1 minus combined income tax rate of 23.1693%).
6/ Amount from Column (c).