THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Duke Energy Progress, LLC	**End of** 2017/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules __________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Duke Energy Progress, LLC	02 Year/Period of Report End of 2017/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 550 South Tryon Street, Charlotte, NC 28202	
05 Name of Contact Person Susan Eliason	06 Title of Contact Person Manager Accounting
07 Address of Contact Person *(Street, City, State, Zip Code)* 550 South Tryon Street, Charlotte, NC 28202	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(704) 382-1061	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name William E. Currens, Jr. 02 Title SVP, Chief Accting Off & Controller	William E. Currens, Jr.	04/12/2018

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

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	04/12/2018	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [ ] No annual report to stockholders is prepared		

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	04/12/2018	End of 2017/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

William E. Currens, Jr.
Senior Vice President, Chief Accounting Officer and Controller
550 South Tryon Street
Charlotte, NC 28202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

On August 1, 2015 the respondent converted its form of organization from a North Carolina corporation to a North Carolina limited liability company. The respondent was originally incorporated as a North Carolina corporation on April 6, 1926.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric Power in the states of North Carolina and South Carolina.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

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	04/12/2018	End of 2017/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Duke Energy Progress, LLC is a wholly-owned subsidiary of Duke Energy Corporation, a Delaware Corporation.

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	04/12/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	CaroHome, LLC	Affordable Housing Investment	99	
2	CaroFund, Inc.	Investment	100	
3	Capitan Corporation	Land Rights Title Holder	100	
4	Duke Energy Progress Receivables LLC	Receivables Finance	100	
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FOOTNOTE DATA

Schedule Page: 103 Line No.: 1 Column: d

The remaining 1.0% is owned by CaroFund, Inc.

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	04/12/2018	End of 2017/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chief Executive Officer	Lynn J. Good	1,350,000
2			
3	Executive Vice President, effective 5/16/16	Dhiaa M. Jamil	787,500
4	Chief Operating Officer, effective 5/1/16		
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9	Executive Vice President	Julia S. Janson	625,000
10	Chief Legal Officer		
11	External Affairs		
12	Secretary		
13			
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15			
16	Executive Vice President, External Affairs and	Jennifer L. Weber	82,062
17	Strategic Policy resigned 2/28/16		
18			
19	Executive Vice President, Customer and Delivery	Lloyd M. Yates	686,753
20	Operations, effective 9/1/16		
21	Executive Vice President, Market Solutions		
22	effective 9/1/16		
23	President, Carolinas Region, resigned 9/1/16		
24			
25	President, South Carolina	Clark S. Gillespy	272,824
26	resigned 12/31/16		
27			
28	President, North Carolina effective 09/01/2015	David B. Fountain	379,147
29			
30	Executive Vice President effective 08/06/2013	Steven K. Young	693,000
31	Chief Financial Officer		
32			
33	Treasurer and Senior Vice President, Tax effective 2/1/6	Stephen Gerard De May	372,468
34	Treasurer, effective 2/1/16		
35	Senior Vice President, resigned 2/1/16		
36	Treasurer, resigned 2/1/16		
37			
38	Senior Vice President, effective 5/16/16	William E. Currens Jr.	305,910
39	Chief Accounting Officer, effective 5/16/16		
40	Controller, effective 5/16/16		
41			
42	Executive Vice President, effective 5/1/16	Melissa H. Anderson	509,850
43	Administration and Chief Human Resources Officer,		
44	effective 5/1/16		

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	04/12/2018	End of 2017/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Senior Vice President and Chief Human Resources		
2	Officer, resigned 5/1/16		
3			
4	President, Duke Energy International	Andrea Bertone	366,425
5	resigned 12/31/16		
6			
7	Executive Vice President, Energy Solutions,	Doug Esamann	585,000
8	effective 9/1/16		
9	President, Midwest and Florida Regions,		
10	effective 9/1/16		
11	Executive Vice President, resigned 9/1/16		
12	President, Midwest and Florida Regions,		
13	resigned 9/1/16		
14			
15	Senior Vice President, resigned 5/16/16	Brian D. Savoy	350,000
16	Chief Accounting Officer, resigned 5/16/16		
17	Controller, through 5/15/16		
18			
19	EVP & President, Natural Gas	Franklin L. Yoho	490,000
20	Effective 10/01/16		
21			
22	President, Commercial Portfolio	Greg Wolf	192,070
23	resigned 7/7/16		
24			
25	President, South Carolina	Ghartey-Tagoe, Kodwo	333,176
26	Effective 01/01/2017		
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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	04/12/2018	End of 2017/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Douglas F Esamann	550 South Tryon Street, Charlotte, NC 28202
2	Executive Vice President, Energy Solutions	
3	President, Midwest and Florida Regions	
4		
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6	Lynn J. Good	550 South Tryon Street, Charlotte, NC 28202
7	Chief Executive Officer	
8		
9	Dhiaa M. Jamil	550 South Tryon Street, Charlotte, NC 28202
10	Executive Vice President	
11	Chief Operating Officer	
12		
13	Julia S. Janson	550 South Tryon Street, Charlotte, NC 28202
14	Executive Vice President, External Affairs	
15	Chief Legal Officer	
16	Secretary	
17		550 South Tryon Street, Charlotte, NC 28202
18	Lloyd M. Yates	
19	Executive Vice President, Customer and Delivery Operations	
20	President, Carolinas Region	
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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	04/12/2018	End of 2017/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Joint Open Access Transmission Tariff (OATT)	ER17-2567
2	RS 172	ER17-1839
3	RS 180	ER17-1839
4	RS 182	ER17-2439
5	RS 184	ER17-1553
6	RS 195	ER18-253
7	RS 197	ER18-207
8	RS 200	ER17-1557
9	RS 210	ER18-253
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Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170515-5189	05/15/2017	ER09-1165	Annual Transmission Update	Joint Open Access Transmission Tariff
2					
3					
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Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None

2. See p.123, Notes to Financial Statements, Note 2 "Acquisitions and Dispositions"

3. None

4. None

5. None

6. See p.123, Notes to Financial Statements, Note 6, "Debt and Credit Facilities"

7. None

8. During the third quarter of 2017, Duke Energy Progress granted a 3% general wage increase for non-represented craft employees totaling $4,290,690 in annualized costs. This increase excludes promotions, demotions, and job reclassifications.

9. See p.123, Notes to Financial Statements, Note 4, "Regulatory Matters" and Note 5,"Commitments and Contingencies"

10. None

11. Reserved

12. None

13. There are no changes to major security holders and voting powers of Duke Energy Progress, LLC that occurred during 2017.
    The officer and director appointments and resignations that occurred

    during 2017 are as follows:

Appointments Effective December 2017

Steven D. Capps	Senior Vice President, Nuclear Corporate
T. Preston Gillespie Jr.	Senior Vice President and Chief Nuclear Officer
Kelvin Henderson	Senior Vice President, Nuclear Operations (NC)
Kim Maza	Vice President, Nuclear Corporate Governance & Oversight

Appointments Effective October 2017

L. Stanford Sherrill Jr.	Vice President, Workforce Developments, Employee and Labor Relations

RESIGNATIONS Effective December 2017

T. Preston Gillespie Jr.	Senior Vice President, and Nuclear Chief Operating Officer
Kelvin Henderson	Senior Vice President, Nuclear Corporate
John W. Pitesa	Senior Vice President and Chief Nuclear Officer

RESIGNATIONS Effective October 2017

L. Stanford Sherrill Jr.	Vice President, Employee Relations and Labor Relations

Appointments Effective August 2017

Davis, Y. Joni	Vice President, Marketing and Customer Engagement

Barbara A. Higgins	Senior Vice President and Chief Customer Officer
Retha Hunsicker	Vice President, Customer Connect Solutions

Appointments Effective May 2017

Donna T. Council	Vice President, Human Resources Business Partners
Julia S. Janson	Executive Vice President, External Affairs, Chief Legal Officer and Secretary
Catherine B. Stancombe	Vice President, Enterprise Operational Excellence
Charles R. Whitlock	Senior Vice President, Strategic Growth Initiatives

Appointments Effective April 2017

Swati V. Daji	Senior Vice President, Chief Procurement Officer
Eric S. Grant	Vice President, Fuels and Systems Optimization

RESIGNATIONS Effective May 2017

Julia S. Janson	Executive Vice President, Chief Legal Officer and Secretary
Catherine B. Stancombe	Vice President, Human Resources Business Partners

RESIGNATIONS Effective April 2017

Swati V. Daji	Senior Vice President, Fuels and System Optimization

Appointments Effective March 2017

Gary J. Hebbeler	Vice President, Gas Operations
Emily G.Henson	Vice President, Distribution Construction and Maintenance - Carolinas West
Rufus Stanley Jackson	Vice President, Distribution Construction and Maintenance - Carolinas East
Louis Renje	Vice President, Federal Government Affairs and Strategic Policy

Appointments Effective February 2017

Jeffrey A. Corbett	Senior Vice President, Distribution Engineering and Technical Customer Relations
David J. Maxon	Senior Vice President, Distribution Construction and Maintenance
John F. Smith III	Senior Vice President, Distribution Grid Performance and Contractor Operations
Benjamin C. Waldrep	Senior Vice President and Chief Security Officer

Appointments Effective January 2017

Robert F. Caldwell	Senior Vice President and President, Duke Energy Renewables and Distributed Energy
Joseph W. Donahue	Vice President, Nuclear Engineering
Paul Draovitch	Senior Vice President, Environmental,Health and Safety
Kodwo Ghartey-Tagoe	President, South Carolina
Ernest J. Kapopoulos Jr.	Site Vice President, Robinson

RESIGNATIONS Effective March 2017

Robert E. Combs	Vice President, Distribution, Maintenance & Construction - Carolinas West
Robert J. Duncan II	Senior Vice President, Nuclear Operations (NC)

RESIGNATIONS Effective February 2017

Jeffrey A. Corbett	Senior Vice President, Chief Procurement Officer
Terrell N. Garren	Vice President and Chief Security Officer
John F. Smith III	Senior Vice President, Carolinas Distribution

	Operations
Benjamin C. Waldrep	Vice President, Operational Excellence

RESIGNATIONS Effective January 2017

Charles Keith Beam	Vice President, Customer Information Systems IT
Robert F. Caldwell	President, Duke Energy Renewables and Distributed Energy Technology
Paul Draovitch	Senior Vice President, Fossil Hydro Operations
Christopher M. Fallon	Vice President, Nuclear Development
Clark S. Gillespy	President, South Carolina
Richard Michael Glover	Site Vice President, Robinson
Ernest J. Kapopoulos Jr.	Vice President, Operations Support
Harry K. Sideris	Senior Vice President, Environmental Health and Safety

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	04/12/2018	End of 2017/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	27,640,413,426	26,516,624,323
3	Construction Work in Progress (107)	200-201	1,422,282,356	1,303,611,534
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		29,062,695,782	27,820,235,857
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	11,818,924,780	11,379,160,840
6	Net Utility Plant (Enter Total of line 4 less 5)		17,243,771,002	16,441,075,017
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	372,875,189	311,017,469
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	62,792,088
9	Nuclear Fuel Assemblies in Reactor (120.3)		842,377,497	836,611,115
10	Spent Nuclear Fuel (120.4)		344,303,937	269,992,039
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	830,851,022	730,006,410
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		728,705,601	750,406,301
14	Net Utility Plant (Enter Total of lines 6 and 13)		17,972,476,603	17,191,481,318
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		36,739,137	35,107,688
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,137,682	9,888,862
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	20,150,772	18,169,203
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		41,622,284	41,410,010
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,872,581,764	2,473,469,794
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		551,380	8,897,044
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,959,507,655	2,567,164,877
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		16,603,425	10,348,376
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		344,026,988	330,199,653
41	Other Accounts Receivable (143)		120,073,290	5,234,476
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		6,458,355	5,968,264
43	Notes Receivable from Associated Companies (145)		0	164,938,000
44	Accounts Receivable from Assoc. Companies (146)		57,088,400	74,661,835
45	Fuel Stock (151)	227	242,760,869	262,286,714
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	739,132,797	780,734,297
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	134,782	163,973
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	109,087,159	86,749,196

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	04/12/2018	End of 2017/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	35,393,695	32,787,942
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		72,816,399	44,574,206
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		326,380	131,731
61	Accrued Utility Revenues (173)		143,197,755	125,363,222
62	Miscellaneous Current and Accrued Assets (174)		563,130	0
63	Derivative Instrument Assets (175)		0	723,557
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		2,172,282	44,131,820
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		551,380	8,897,044
67	Total Current and Accrued Assets (Lines 34 through 66)		1,876,367,616	1,948,163,690
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		42,389,406	39,797,537
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	183,051,153	166,620,786
72	Other Regulatory Assets (182.3)	232	3,419,931,113	3,099,341,503
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,025,345	2,936,284
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		5,088,642	4,503,190
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	394,301,626	490,376,158
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		5,609,529	6,643,127
82	Accumulated Deferred Income Taxes (190)	234	1,775,392,682	2,083,860,008
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		5,830,789,496	5,894,078,593
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		28,639,141,370	27,600,888,478

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	04/12/2018	end of 2017/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	0	0
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,784,376,571	2,784,376,571
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	5,449,057,894	4,860,407,802
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-284,587,146	-286,334,903
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-180,809	-206,646
16	Total Proprietary Capital (lines 2 through 15)		7,948,666,510	7,358,242,824
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,823,485,000	6,473,485,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	150,000,000	150,000,000
21	Other Long-Term Debt (224)	256-257	300,000,000	300,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		16,187,768	16,440,408
24	Total Long-Term Debt (lines 18 through 23)		7,257,297,232	6,907,044,592
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		136,548,646	139,410,389
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,952,093	8,664,132
29	Accumulated Provision for Pensions and Benefits (228.3)		232,708,439	232,000,482
30	Accumulated Miscellaneous Operating Provisions (228.4)		18,257,902	21,985,322
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		5,556,146	5,574,632
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		3,397,097	156,050
34	Asset Retirement Obligations (230)		4,673,454,040	4,696,982,200
35	Total Other Noncurrent Liabilities (lines 26 through 34)		5,077,874,363	5,104,773,207
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		404,314,214	592,188,925
39	Notes Payable to Associated Companies (233)		239,986,000	0
40	Accounts Payable to Associated Companies (234)		172,996,605	220,219,478
41	Customer Deposits (235)		129,255,428	141,048,805
42	Taxes Accrued (236)	262-263	71,459,237	107,826,421
43	Interest Accrued (237)		102,815,253	102,928,865
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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	04/12/2018	end of 2017/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		5,530,414	5,107,439
48	Miscellaneous Current and Accrued Liabilities (242)		207,717,863	197,203,719
49	Obligations Under Capital Leases-Current (243)		2,861,742	2,507,196
50	Derivative Instrument Liabilities (244)		6,119,276	5,574,632
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		5,556,146	5,574,632
52	Derivative Instrument Liabilities - Hedges (245)		10,073,679	156,050
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		3,397,097	156,050
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,344,176,468	1,369,030,848
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		25,775,971	23,027,797
57	Accumulated Deferred Investment Tax Credits (255)	266-267	143,330,909	146,399,648
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	25,789,789	56,303,593
60	Other Regulatory Liabilities (254)	278	3,158,363,633	1,228,887,118
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		2,555,356,409	3,902,880,700
64	Accum. Deferred Income Taxes-Other (283)		1,102,510,086	1,504,298,151
65	Total Deferred Credits (lines 56 through 64)		7,011,126,797	6,861,797,007
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		28,639,141,370	27,600,888,478

Schedule Page: 112 Line No.: 34 Column: d

Amount reflects the reclassification of the Current portion of ARO liabilities from Account 242 to Account 230 in order to be consistent with the current year presentation.

Schedule Page: 112 Line No.: 48 Column: d

Amount reflects the reclassification of the Current portion of ARO liabilities from Account 242 to Account 230 in order to be consistent with the current year presentation.

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,125,684,512	5,265,756,021		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,492,514,198	2,740,384,579		
5	Maintenance Expenses (402)	320-323	472,231,323	562,811,662		
6	Depreciation Expense (403)	336-337	633,577,367	604,487,167		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	37,989,554	31,071,436		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	12,758,733	12,758,733		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		31,048,241	30,447,884		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		284,278,998	165,027,228		
13	(Less) Regulatory Credits (407.4)		237,323,828	161,345,859		
14	Taxes Other Than Income Taxes (408.1)	262-263	153,535,056	153,758,259		
15	Income Taxes - Federal (409.1)	262-263	-91,946,206	-53,582,117		
16	- Other (409.1)	262-263	2,562,304	-23,847,119		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,186,870,107	1,223,186,084		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	760,715,065	840,004,091		
19	Investment Tax Credit Adj. - Net (411.4)	266	-3,380,372	-5,304,895		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		378,052	364,445		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,213,622,358	4,439,484,506		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		912,062,154	826,271,515		

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	04/12/2018	End of 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
5,125,684,512	5,265,756,021					2
						3
2,492,514,198	2,740,384,579					4
472,231,323	562,811,662					5
633,577,367	604,487,167					6
						7
37,989,554	31,071,436					8
12,758,733	12,758,733					9
31,048,241	30,447,884					10
						11
284,278,998	165,027,228					12
237,323,828	161,345,859					13
153,535,056	153,758,259					14
-91,946,206	-53,582,117					15
2,562,304	-23,847,119					16
1,186,870,107	1,223,186,084					17
760,715,065	840,004,091					18
-3,380,372	-5,304,895					19
						20
						21
378,052	364,445					22
						23
						24
4,213,622,358	4,439,484,506					25
912,062,154	826,271,515					26

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	04/12/2018	End of 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		912,062,154	826,271,515		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		-7			
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		31,097,036	25,518,661		
34	(Less) Expenses of Nonutility Operations (417.1)		24,078,603	14,426,348		
35	Nonoperating Rental Income (418)		-553,739	-524,788		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,789,130	450,644		
37	Interest and Dividend Income (419)		1,693,291	3,062,143		
38	Allowance for Other Funds Used During Construction (419.1)		47,441,028	49,614,088		
39	Miscellaneous Nonoperating Income (421)		21,335,420	10,386,161		
40	Gain on Disposition of Property (421.1)		1,291,897	1,274,712		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		80,015,453	75,355,273		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,636,650	118,435		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,301,970	37,429,332		
46	Life Insurance (426.2)		-489,388	-1,078,345		
47	Penalties (426.3)		389,218	700,300		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,702,960	2,526,385		
49	Other Deductions (426.5)		25,332,275	1,811,310		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		31,873,685	41,507,417		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,072,971	1,790,277		
53	Income Taxes-Federal (409.2)	262-263	-2,417,291	-4,877,441		
54	Income Taxes-Other (409.2)	262-263	-204,716	-1,164,465		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	11,814,863	21,619,976		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	51,014,160	15,873,635		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-39,748,333	1,494,712		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		87,890,101	32,353,144		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		285,462,085	264,245,568		
63	Amort. of Debt Disc. and Expense (428)		5,054,777	5,159,109		
64	Amortization of Loss on Reaquired Debt (428.1)		1,033,597	1,073,351		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		5,557,512	1,889,048		
68	Other Interest Expense (431)		8,404,622	3,708,098		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		20,958,187	16,851,277		
70	Net Interest Charges (Total of lines 62 thru 69)		284,554,406	259,223,897		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		715,397,849	599,400,762		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		715,397,849	599,400,762		

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		4,855,687,557	4,557,197,977
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Transfer to Unappropriated RE (Account 216.1)		41,373	34,012
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		41,373	34,012
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		713,608,719	598,950,118
17	Appropriations of Retained Earnings (Acct. 436)			
18	Hydro Project Reserve Amortization	215.1	-876,625	(494,550)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-876,625	(494,550)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividend		-125,000,000	(300,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-125,000,000	(300,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		5,443,461,024	4,855,687,557
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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	04/12/2018	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		5,596,870	4,720,245
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		5,596,870	4,720,245
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		5,449,057,894	4,860,407,802
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-286,334,903	(286,751,535)
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,789,130	450,644
51	(Less) Dividends Received (Debit)			
52			-41,373	(34,012)
53	Balance-End of Year (Total lines 49 thru 52)		-284,587,146	(286,334,903)

Schedule Page: 118 Line No.: 18 Column: c

The Hydro Project Reserve Amortization amount is based and calculated per the Federal Power Commission license for Project No. 2206, issued February 11, 1958 and by addition of Article No. 27, effective May 11, 1977 for Blewett/Tillery.

Schedule Page: 118 Line No.: 18 Column: d

The Hydro Project Reserve Amortization amount is based and calculated per the Federal Power Commission license for Project No. 2206, issued February 11, 1958 and by addition of Article No. 27, effective May 11, 1977 for Blewett/Tillery.

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	715,397,849	599,400,762
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	633,577,367	604,487,167
5	Amortization and Accretion	326,697,066	304,012,226
6	Net (Increase) Decrease in Mark-to-Market Hedging Transactions	-3,535,981	4,425,410
7	Contributions to Company-Sponsored Pension Plans	-1,287	-23,739,545
8	Deferred Income Taxes (Net)	386,955,745	388,928,334
9	Investment Tax Credit Adjustment (Net)	-3,380,372	-5,304,895
10	Net (Increase) Decrease in Receivables	-114,247,670	119,196,972
11	Net (Increase) Decrease in Inventory	58,550,783	12,300,856
12	Net (Increase) Decrease in Allowances Inventory	-33,022,444	-26,396,581
13	Net Increase (Decrease) in Payables and Accrued Expenses	-322,389,286	322,632,164
14	Net (Increase) Decrease in Other Regulatory Assets	-37,029,778	35,266,347
15	Net Increase (Decrease) in Other Regulatory Liabilities	-97,693,807	26,379,454
16	(Less) Allowance for Other Funds Used During Construction	47,441,028	49,614,088
17	(Less) Undistributed Earnings from Subsidiary Companies	1,789,130	450,644
18	Other (provide details in footnote):	-249,059,700	-352,401,923
19	Accrued Pension and Other Post-Retirement Benefit Costs Adj to NI	-19,705,406	-32,078,748
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,191,882,921	1,927,043,268
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,597,038,770	-1,469,812,476
27	Gross Additions to Nuclear Fuel	-162,722,373	-209,562,613
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-494,282	-1,174,784
30	(Less) Allowance for Other Funds Used During Construction	-47,441,028	49,614,088
31	Other (provide details in footnote):		
32	Additions from Affiliated Companies	-4,361,149	-2,623,342
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,717,175,546	-1,732,787,303
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	52	4,211,328
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	164,745,561	-165,904,339
40	Contributions and Advances from Assoc. and Subsidiary Companies		74,931
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,249,133,802	-1,657,522,217
45	Proceeds from Sales of Investment Securities (a)	1,211,437,038	1,619,065,118

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	-50,585,970	22,769,806
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,640,712,667	-1,910,092,676
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	817,075,186	508,607,709
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	817,075,186	508,607,709
71	Other Financing Activities (provide details in footnote)	-6,659,009	-4,255,524
72	Payments for Retirement of:		
73	Long-term Debt (b)	-470,317,382	-15,746,073
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	239,986,000	-209,278,000
78	Net Decrease in Short-Term Debt (c)		
79	Dividends to Parent	-125,000,000	-300,000,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	455,084,795	-20,671,888
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	6,255,049	-3,721,296
87			
88	Cash and Cash Equivalents at Beginning of Period	10,348,376	14,069,672
89			
90	Cash and Cash Equivalents at End of period	16,603,425	10,348,376

Schedule Page: 120 Line No.: 18 Column: b

Asset retirement obligation liabilities settled	$ (191,519,065)
Change in prepaid and other current assets	(29,722,324)
Change in other noncurrent assets	(25,380,462)
Change in deferred credits and other long-term liabilities	(11,140,881)
Payment of charitable contributions related to Piedmont merger commitments	(7,375,000)
Gain on sale of assets	(3,137,278)
Equity method investment income	618,475
Impairment	18,596,835
	$ (249,059,700)

Schedule Page: 120 Line No.: 53 Column: b

Year to date Cost of Removal Activity	$ (52,165,993)
Death proceeds from COLI and Rabbi Trust	1,580,023
	$ (50,585,970)

Schedule Page: 120 Line No.: 71 Column: b

Primarily unamortized debt expenses associated with:

Issuances of LT Debt	$ (5,338,881)
Master Credit Facility fees	(1,320,128)
	$ (6,659,009)

Schedule Page: 120 Line No.: 86 Column: b

Significant noncash transactions:

Accrued capital expenditures	$ 191,130,689

Supplemental Disclosures:

Cash paid for interest, net of amount capitalized	$ 291,420,459
Cash paid for income taxes, net	$ 58,986,643

Schedule Page: 120 Line No.: 88 Column: b

Cash and Cash Equivalents at Beginning of Period include the following:

Cash (131)	$ 10,348,376

Schedule Page: 120 Line No.: 90 Column: b

Cash and Cash Equivalents at End of Period include the following:

Cash (131)	$ 16,603,425

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

This Federal Energy Regulatory Commission (FERC) Form 1 has been prepared in conformity with the requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles in the United States of America (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

(a) GAAP requires that public business enterprises report certain information about operating segments in complete sets of financial statements of the enterprise and certain information about their products and services, which are not required for FERC reporting purposes.
(b) GAAP requires that majority-owned subsidiaries be consolidated for financial reporting purposes. FERC requires that majority-owned subsidiaries be separately reported as Investment in Subsidiary Companies unless an appropriate waiver has been granted by the FERC.
(c) FERC requires that income or losses of an unusual nature and infrequent occurrence, which would significantly distort the current year's income, be recorded as extraordinary income or deductions, respectively.
(d) GAAP requires that removal and nuclear decommissioning costs for property that do not have an associated legal retirement obligation be presented as a regulatory liability on the Balance Sheet. These costs are presented as accumulated depreciation on the Balance Sheet for FERC reporting purposes.
(e) GAAP requires the regulatory assets and liabilities resulting from the implementation of ASC 740-10 (formerly SFAS No. 109) be presented as a net amount on the balance sheet. For FERC reporting purposes, these assets and liabilities are presented separately and are included in the Other Regulatory Asset and Other Regulatory Liability line items.
(f) GAAP requires that the current portion of regulatory assets and regulatory liabilities be reported as current assets and current liabilities,respectively, on the Balance Sheet. FERC requires that the current portion of regulatory assets and liabilities be reported as Regulatory Assets within Deferred Debits and Regulatory Liabilities within Deferred Credits, respectively.
(g) GAAP requires that the current portion of long-term debt and preferred stock be reported as a current liability on the Balance Sheet. FERC requires that the current portion of long-term debt and preferred stock be reported as Long-term Debt and Proprietary Capital.
(h) GAAP requires that any deferred costs associated with a specific debt issuance to be presented as a reduction to the debt amount on the Balance Sheet. FERC requires any Unamortized Debt Expense to be separately stated as a Deferred Debit on the Balance Sheet.
(i) GAAP requires that certain account balances within financial statement line items which are not in the natural position for that line item (e.g.,an account within Accounts Receivable with a credit balance) be reclassed to the appropriate side of the Balance Sheet. FERC does not require certain accounts which are not in a natural position for their respective line item to be reclassed, as long as the line item in total is in its natural position.
(j) GAAP requires that regulated assets that are abandoned or retired early, including the cost of the asset and its associated accumulated depreciation, be reclassified to a separate regulatory asset on the Balance Sheet. For FERC reporting purposes, those assets which have been abandoned but are still operating are maintained in their original balance sheet accounts.
(k) GAAP requires that the current portion of Asset Retirement Obligations be reported as current liabilities on the Balance Sheet. For FERC reporting purposes, these liabilities are not reported separately and are reflected as Asset Retirement Obligations within the Other Noncurrent Liabilities section of the Balance Sheet
(l) With the adoption of Accounting Standards Update (ASU) No. 2017-17 January 1, 2018, GAAP requires that the service cost related to pensions and PBOP be reported with other compensation costs arising from services rendered by employees during the period be included in a subtotal of income from operations. Only the service cost component may be elibible for capitalization if all other capitalization criteria are met For FERC reporting purposes, costs related to pensions and PBOP will be included in the Net Utility Operating Income of the income statement. Duke has made a non-revocable election to capitalize only the service cost component of pension and PBOP costs, upon implementing ASU No. 2017-07. This change is not expected to have a material impact on the financial statements.

The Combined Notes To Consolidated Financial Statements below are as published in the fourth quarter ended December 31, 2017 Form 10-K/A (includes Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Duke Energy Florida, LLC, Duke Energy Ohio, Inc., Duke Energy Indiana, LLC and Piedmont Natural Gas Company, Inc.) filed on February 22, 2018. See "Index to the Combined Notes to Consolidated Financial Statements" for a listing of applicable notes for Duke Energy Progress, LLC.

On February 23, 2018, the North Carolina Utilities Commission (the "NCUC") issued an order (the "Order") approving, without modification, the Agreement and Stipulation of Partial Settlement dated November 22, 2017, between Duke Energy Progress, LLC ("DEP") and the Public Staff - North Carolina Utilities Commission (the "Public Staff") (the "Settlement") which settled certain issues in the rate case proceeding which DEP filed on June 1, 2017, with the NCUC. The Settlement includes, among other things, a return on equity of 9.9% based upon a capital structure of 52% equity and 48% debt.

The Order also resolves the outstanding items in the rate case proceeding, including the recovery of deferred storm costs and the recovery of deferred coal ash costs which were deemed to be reasonable and prudent, known and measureable and used and useful in the provision of service to customers.

As a result of the Order, Duke Energy will take an estimated pre-tax charge of approximately $100 million in the first quarter of 2018, primarily related to the coal ash basin disallowance and management penalty and deferred storm cost adjustments.

Duke Energy Progress, LLC will be making certain rate filings with the Federal Energy Regulatory Commission associated with recovery of items addressed in the retail rate case from wholesale customers.

Index to Combined Notes To Consolidated Financial Statements

The notes to the consolidated financial statements are a combined presentation. The following table indicates the registrants to which the notes apply.

	Applicable Notes																								
Registrant	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Duke Energy Corporation	•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•	•	•	•	•	•	•	•
Duke Energy Carolinas, LLC	•		•	•	•	•		•	•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Progress Energy, Inc.	•		•	•	•	•	•		•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Progress, LLC	•		•	•	•	•			•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Florida, LLC	•		•	•	•	•			•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Ohio, Inc.	•	•	•	•	•	•		•	•	•	•		•	•		•	•		•	•	•	•	•	•	•
Duke Energy Indiana, LLC	•		•	•	•	•		•	•	•	•		•	•	•	•	•		•	•	•	•	•	•	•
Piedmont Natural Gas Company, Inc.	•	•	•	•	•	•			•	•	•	•	•	•	•	•	•		•	•	•	•	•	•	•

Tables within the notes may not sum across due to (i) Progress Energy's consolidation of Duke Energy Progress, Duke Energy Florida and other subsidiaries that are not registrants and (ii) subsidiaries that are not registrants but included in the consolidated Duke Energy balances.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Consolidation

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the Federal Energy Regulatory Commission (FERC). Duke Energy operates in the United States (U.S.) primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also subsidiary registrants, including Duke Energy Carolinas, LLC (Duke Energy Carolinas); Progress Energy, Inc. (Progress Energy); Duke Energy Progress, LLC (Duke Energy Progress); Duke Energy Florida, LLC (Duke Energy Florida); Duke Energy Ohio, Inc. (Duke Energy Ohio); Duke Energy Indiana, LLC (Duke Energy Indiana) and Piedmont Natural Gas Company, Inc. (Piedmont). When discussing Duke Energy’s consolidated financial information, it necessarily includes the results of its seven separate subsidiary registrants (collectively referred to as the Subsidiary Registrants), which along with Duke Energy, are collectively referred to as the Duke Energy Registrants.

In October 2016, Duke Energy completed the acquisition of Piedmont. Duke Energy's consolidated financial statements include Piedmont's results of operations and cash flows activity subsequent to the acquisition date. Effective November 1, 2016, Piedmont's fiscal year-end was changed from October 31 to December 31, the year-end of Duke Energy. A transition report was filed on Form 10-Q (Form 10-QT) as of December 31, 2016, for the transition period from November 1, 2016, to December 31, 2016. See Note 2 for additional information regarding the acquisition.

In December 2016, Duke Energy completed an exit of the Latin American market to focus on its domestic regulated business, which was further bolstered by the acquisition of Piedmont. The sale of the International Energy business segment, excluding an equity method investment in National Methanol Company (NMC), was completed through two transactions including a sale of assets in Brazil to China Three Gorges (Luxembourg) Energy S.à.r.l. (CTG) and a sale of Duke Energy's remaining Latin American assets in Peru, Chile, Ecuador, Guatemala, El Salvador and Argentina to ISQ Enerlam Aggregator, L.P. and Enerlam (UK) Holding Ltd. (I Squared) (collectively, the International Disposal Group). See Note 2 for additional information on the sale of International Energy.

The information in these combined notes relates to each of the Duke Energy Registrants as noted in the Index to Combined Notes to Consolidated Financial Statements. However, none of the Subsidiary Registrants make any representation as to information related solely to Duke Energy or the Subsidiary Registrants of Duke Energy other than itself.

These Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of the Duke Energy Registrants and subsidiaries where the respective Duke Energy Registrants have control. These Consolidated Financial Statements also reflect the Duke Energy Registrants' proportionate share of certain jointly owned generation and transmission facilities. Substantially all of the Subsidiary Registrants' operations qualify for regulatory accounting.

Duke Energy Carolinas is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Carolinas is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (PSCSC), U.S. Nuclear Regulatory Commission (NRC) and FERC.

Progress Energy is a public utility holding company headquartered in Raleigh, North Carolina, subject to regulation by FERC. Progress Energy conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida.

Duke Energy Progress is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Progress is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC.

Duke Energy Florida is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. Duke Energy Florida is subject to the regulatory provisions of the Florida Public Service Commission (FPSC), NRC and FERC.

Duke Energy Ohio is a regulated public utility primarily engaged in the transmission and distribution of electricity in portions of Ohio and Kentucky, the generation and sale of electricity in portions of Kentucky and the transportation and sale of natural gas in portions of Ohio and Kentucky. Duke Energy Ohio conducts competitive auctions for retail electricity supply in Ohio whereby the energy price is recovered from retail customers and recorded in Operating Revenues on the Consolidated Statements of Operations and Comprehensive Income. Operations in Kentucky are conducted through its wholly owned subsidiary, Duke Energy Kentucky, Inc. (Duke Energy Kentucky). References herein to Duke Energy Ohio collectively include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the Public Utilities Commission of Ohio (PUCO), Kentucky Public Service Commission (KPSC) and FERC. On April 2, 2015, Duke Energy completed the sale of its nonregulated Midwest generation business, which sold power into wholesale energy markets, to a subsidiary of Dynegy Inc. (Dynegy). For further information about the sale of the Midwest Generation business, refer to Note 2. Substantially all of Duke Energy Ohio's operations that remain after the sale qualify for regulatory accounting.

Duke Energy Indiana is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Indiana. Duke Energy Indiana is subject to the regulatory provisions of the Indiana Utility Regulatory Commission (IURC) and FERC.

Piedmont is a regulated public utility primarily engaged in the distribution of natural gas in portions of North Carolina, South Carolina and Tennessee. Piedmont is subject to the regulatory provisions of the NCUC, PSCSC, Tennessee Public Utility Commission (TPUC) and FERC.

Certain prior year amounts have been reclassified to conform to the current year presentation.

Other Current Assets and Liabilities

The following table provides a description of amounts included in Other within Current Assets or Current Liabilities that exceed 5 percent of total Current Assets or Current Liabilities on the Duke Energy Registrants' Consolidated Balance Sheets at either December 31, 2017, or 2016.

		December 31,	
(in millions)	**Location**	**2017**	**2016**
Duke Energy			
Accrued compensation	Current Liabilities	**$ 757**	$ 765
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 252**	$ 248
Customer deposits	Current Liabilities	**121**	155
Progress Energy			
Income taxes receivable	Current Assets	**$ 278**	$ 19
Customer deposits	Current Liabilities	**338**	363
Duke Energy Progress			
Customer deposits	Current Liabilities	**$ 129**	$ 141
Accrued compensation	Current Liabilities	**132**	135
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 208**	$ 222
Duke Energy Ohio			
Income taxes receivable	Current Assets	**$ 36**	$ 16
Customer deposits	Current Liabilities	**46**	62
Duke Energy Indiana			
Customer deposits	Current Liabilities	**$ 45**	$ 44
Piedmont			
Income taxes receivable	Current Assets	**$ 43**	$ 9

Discontinued Operations

The results of operations of the International Disposal Group as well as Duke Energy Ohio's nonregulated Midwest Generation business and Duke Energy Retail Sales, LLC (collectively, Midwest Generation Disposal Group) have been classified as Discontinued Operations on Duke Energy's Consolidated Statements of Operations. Duke Energy has elected to present cash flows of discontinued operations combined with cash flows of continuing operations. Unless otherwise noted, the notes to these consolidated financial statements exclude amounts related to discontinued operations for all periods presented. See Note 2 for additional information.

Amounts Attributable to Controlling Interests

For the year ended December 31, 2017, the Loss From Discontinued Operations, net of tax on Duke Energy's Consolidated Statement of Operations is entirely attributable to controlling interest. The following table presents Net Income Attributable to Duke Energy Corporation for continuing operations and discontinued operations for the years ended December 31, 2016, and 2015.

	Year ended December 31,	
(in millions)	**2016**	**2015**
Income from Continuing Operations	$ 2,578	$ 2,654
Income from Continuing Operations Attributable to Noncontrolling Interests	7	9
Income from Continuing Operations Attributable to Duke Energy Corporation	$ 2,571	$ 2,645
(Loss) Income From Discontinued Operations, net of tax	$ (408)	$ 177
Income from Discontinued Operations Attributable to Noncontrolling Interests, net of tax	11	6
(Loss) Income From Discontinued Operations Attributable to Duke Energy Corporation, net of tax	$ (419)	$ 171
Net Income	$ 2,170	$ 2,831
Net Income Attributable to Noncontrolling Interests	18	15
Net Income Attributable to Duke Energy Corporation	$ 2,152	$ 2,816

Significant Accounting Policies

Use of Estimates

In preparing financial statements that conform to generally accepted accounting principles (GAAP) in the U.S., the Duke Energy Registrants must make estimates and assumptions that affect the reported amounts of assets and liabilities, the reported amounts of revenues and expenses and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The majority of the Duke Energy Registrants’ operations are subject to price regulation for the sale of electricity and natural gas by state utility commissions or FERC. When prices are set on the basis of specific costs of the regulated operations and an effective franchise is in place such that sufficient natural gas or electric services can be sold to recover those costs, the Duke Energy Registrants apply regulatory accounting. Regulatory accounting changes the timing of the recognition of costs or revenues relative to a company that does not apply regulatory accounting. As a result, regulatory assets and regulatory liabilities are recognized on the Consolidated Balance Sheets. Regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process. See Note 4 for further information.

Regulatory accounting rules also require recognition of a disallowance (also called "impairment") loss if it becomes probable that part of the cost of a plant under construction (or a recently completed plant or an abandoned plant) will be disallowed for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made. These disallowances can require judgments on allowed future rate recovery.

When it becomes probable that regulated generation, transmission or distribution assets will be abandoned, the cost of the asset is removed from plant in service. The value that may be retained as a regulatory asset on the balance sheet for the abandoned property is dependent upon amounts that may be recovered through regulated rates, including any return. As such, an impairment charge could be partially or fully offset by the establishment of a regulatory asset if rate recovery is probable. The impairment for a disallowance of costs for regulated plants under construction, recently completed or abandoned is based on discounted cash flows.

Regulated Fuel and Purchased Gas Adjustment Clauses

The Duke Energy Registrants utilize cost-tracking mechanisms, commonly referred to as fuel adjustment clauses or purchased gas adjustment clauses (PGA). These clauses allow for the recovery of fuel and fuel-related costs, portions of purchased power, natural gas costs and hedging costs through surcharges on customer rates. The difference between the costs incurred and the surcharge revenues is recorded either as an adjustment to Operating Revenues, Operating Expenses – Fuel used in electric generation or Operating Expenses – Cost of natural gas on the Consolidated Statements of Operations, with an off-setting impact on regulatory assets or liabilities.

Cash and Cash Equivalents

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents.

Restricted Cash

The Duke Energy Registrants have restricted cash related primarily to collateral assets, escrow deposits and variable interest entities (VIEs). Restricted cash balances are reflected in Other within Current Assets and in Other within Other Noncurrent Assets on the Consolidated Balance Sheets. At December 31, 2017, and 2016, Duke Energy had restricted cash totaling $147 million and $137 million, respectively.

Inventory

Inventory is used for operations and is recorded primarily using the average cost method. Inventory related to regulated operations is valued at historical cost. Inventory related to nonregulated operations is valued at the lower of cost or market. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to property, plant and equipment when installed. Inventory, including excess or obsolete inventory, is written-down to the lower of cost or market value. Once inventory has been written-down, it creates a new cost basis for the inventory that is not subsequently written-up. Provisions for inventory write-offs were not material at December 31, 2017, and 2016. The components of inventory are presented in the tables below.

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Materials and supplies	**$ 2,293**	**$ 744**	**$ 1,118**	**$ 774**	**$ 343**	**$ 82**	**$ 309**	**$ 2**
Coal	**603**	**192**	**255**	**139**	**116**	**17**	**139**	**—**
Natural gas, oil and other	**354**	**35**	**219**	**104**	**115**	**34**	**2**	**64**
Total inventory	**$ 3,250**	**$ 971**	**$ 1,592**	**$ 1,017**	**$ 574**	**$ 133**	**$ 450**	**$ 66**

	December 31, 2016							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Materials and supplies	$ 2,374	$ 767	$ 1,167	$ 813	$ 354	$ 84	$ 312	$ 1
Coal	774	251	314	148	166	19	190	—
Natural gas, oil and other	374	37	236	115	121	34	2	65

Total inventory	$ 3,522	$ 1,055	$ 1,717	$ 1,076	$ 641	$ 137	$ 504	$ 66

Investments in Debt and Equity Securities

The Duke Energy Registrants classify investments into two categories – trading and available-for-sale. Both categories are recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on trading securities are included in earnings. For certain investments of regulated operations, such as substantially all of the Nuclear Decommissioning Trust Funds (NDTF), realized and unrealized gains and losses (including any other-than-temporary impairments (OTTIs)) on available-for-sale securities are recorded as a regulatory asset or liability. Otherwise, unrealized gains and losses are included in Accumulated Other Comprehensive Income (AOCI), unless other-than-temporarily impaired. OTTIs for equity securities and the credit loss portion of debt securities of nonregulated operations are included in earnings. Investments in debt and equity securities are classified as either current or noncurrent based on management’s intent and ability to sell these securities, taking into consideration current market liquidity. See Note 15 for further information.

Goodwill and Intangible Assets

Goodwill

Effective with Piedmont's change in fiscal year end to December 31, as discussed above, Piedmont changed the date of its annual impairment testing of goodwill from October 31 to August 31 to align with the other Duke Energy Registrants.

Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont perform annual goodwill impairment tests as of August 31 each year at the reporting unit level, which is determined to be an operating segment or one level below. Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont update these tests between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value.

Intangible Assets

Intangible assets are included in Other in Other Noncurrent Assets on the Consolidated Balance Sheets. Generally, intangible assets are amortized using an amortization method that reflects the pattern in which the economic benefits of the intangible asset are consumed or on a straight-line basis if that pattern is not readily determinable. Amortization of intangibles is reflected in Depreciation and amortization on the Consolidated Statements of Operations. Intangible assets are subject to impairment testing and if impaired, the carrying value is accordingly reduced.

Emission allowances permit the holder of the allowance to emit certain gaseous byproducts of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (NO_X). Allowances are issued by the U.S. Environmental Protection Agency (EPA) at zero cost and may also be bought and sold via third-party transactions. Allowances allocated to or acquired by the Duke Energy Registrants are held primarily for consumption. Carrying amounts for emission allowances are based on the cost to acquire the allowances or, in the case of a business combination, on the fair value assigned in the allocation of the purchase price of the acquired business. Emission allowances are expensed to Fuel used in electric generation and purchased power on the Consolidated Statements of Operations.

Renewable energy certificates are used to measure compliance with renewable energy standards and are held primarily for consumption. See Note 11 for further information.

Long-Lived Asset Impairments

The Duke Energy Registrants evaluate long-lived assets, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. An impairment exists when a long-lived asset’s carrying value exceeds the estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. The estimated cash flows may be based on alternative expected outcomes that are probability weighted. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the carrying value of the asset is written-down to its then-current estimated fair value and an impairment charge is recognized.

The Duke Energy Registrants assess fair value of long-lived assets using various methods, including recent comparable third-party sales, internally developed discounted cash flow analysis and analysis from outside advisors. Triggering events to reassess cash flows may include, but are not limited to, significant changes in commodity prices, the condition of an asset or management's interest in selling the asset.

Property, Plant and Equipment

Property, plant and equipment are stated at the lower of depreciated historical cost net of any disallowances or fair value, if impaired. The Duke Energy Registrants capitalize all construction-related direct labor and material costs, as well as indirect construction costs such as general engineering, taxes and financing costs. See "Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized" for information on capitalized financing costs. Costs of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update composite rates and are approved by state utility commissions and/or the FERC when required. The composite weighted average depreciation rates, excluding nuclear fuel, are included in the table that follows.

	Years Ended December 31,		
	2017	**2016**	**2015**
Duke Energy	**2.8%**	2.8%	2.9%
Duke Energy Carolinas	**2.8%**	2.8%	2.8%
Progress Energy	**2.6%**	2.7%	2.6%
Duke Energy Progress	**2.6%**	2.6%	2.6%
Duke Energy Florida	**2.8%**	2.8%	2.7%
Duke Energy Ohio	**2.8%**	2.6%	2.7%
Duke Energy Indiana	**3.0%**	3.1%	3.0%
Piedmont(a)	**2.3%**		

(a) Piedmont's weighted average depreciation rate was 2.4 percent, 2.4 percent, and 2.5 percent for the annualized two months ended December 31, 2016 and for the years ended October 31, 2016 and 2015, respectively.

In general, when the Duke Energy Registrants retire regulated property, plant and equipment, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable the asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as Generation facilities to be retired, net on the Consolidated Balance Sheets. If the asset is no longer operating, the net amount is classified in Regulatory assets on the Consolidated Balance Sheets if deemed recoverable (see discussion of long-lived asset impairments above). When it becomes probable an asset will be abandoned, the cost of the asset and accumulated depreciation is reclassified to Regulatory assets on the Consolidated Balance Sheets for amounts recoverable in rates. The carrying value of the asset is based on historical cost if the Duke Energy Registrants are allowed to recover the remaining net book value and a return equal to at least the incremental borrowing rate. If not, an impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When the Duke Energy Registrants sell entire regulated operating units, or retire or sell nonregulated properties, the original cost and accumulated depreciation and amortization balances are removed from Property, Plant and Equipment on the Consolidated Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

See Note 10 for further information.

Nuclear Fuel

Nuclear fuel is classified as Property, Plant and Equipment on the Consolidated Balance Sheets, except for Duke Energy Florida. Nuclear fuel amounts at Duke Energy Florida were reclassified to Regulatory assets pursuant to the Revised and Restated Stipulation and Settlement Agreement approved in November 2013 among Duke Energy Florida, the Florida Office of Public Counsel (Florida OPC) and other customer advocates (the 2013 Settlement).

Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service. Amortization of nuclear fuel is included within Fuel used in electric generation and purchased power on the Consolidated Statements of Operations. Amortization is recorded using the units-of-production method.

Allowance for Funds Used During Construction and Interest Capitalized

For regulated operations, the debt and equity costs of financing the construction of property, plant and equipment are reflected as AFUDC and capitalized as a component of the cost of property, plant and equipment. AFUDC equity is reported on the Consolidated Statements of Operations as non-cash income in Other income and expenses, net. AFUDC debt is reported as a non-cash offset to Interest Expense. After construction is completed, the Duke Energy Registrants are permitted to recover these costs through their inclusion in rate base and the corresponding subsequent depreciation or amortization of those regulated assets.

AFUDC equity, a permanent difference for income taxes, reduces the effective tax rate (ETR) when capitalized and increases the ETR when depreciated or amortized. See Note 22 for additional information.

For nonregulated operations, interest is capitalized during the construction phase with an offsetting non-cash credit to Interest Expense on the Consolidated Statements of Operations.

Asset Retirement Obligations

Asset retirement obligations (AROs) are recognized for legal obligations associated with the retirement of property, plant and equipment. Substantially all AROs are related to regulated operations. When recording an ARO, the present value of the projected liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The liability is accreted over time. For operating plants, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired plants, the present value of the liability is recorded as a regulatory asset unless determined not to be recoverable.

The present value of the initial obligation and subsequent updates are based on discounted cash flows, which include estimates regarding timing of future cash flows, selection of discount rates and cost escalation rates, among other factors. These estimates are subject to change. Depreciation expense is adjusted prospectively for any changes to the carrying amount of the associated asset. The Duke Energy Registrants receive amounts to fund the cost of the ARO for regulated operations through a combination of regulated revenues and earnings on the NDTF. As a result, amounts recovered in regulated revenues, earnings on the NDTF, accretion expense and depreciation of the associated asset are netted and deferred as a regulatory asset or liability.

Obligations for nuclear decommissioning are based on site-specific cost studies. Duke Energy Carolinas and Duke Energy Progress assume prompt dismantlement of the nuclear facilities after operations are ceased. Duke Energy Florida assumes Crystal River Unit 3 Nuclear Plant (Crystal River Unit 3) will be placed into a safe storage configuration until eventual dismantlement is completed by 2074. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida also assume that spent fuel will be stored on-site until such time that it can be transferred to a yet to be built U.S. Department of Energy (DOE) facility.

Obligations for closure of ash basins are based upon discounted cash flows of estimated costs for site-specific plans, if known, or probability weightings of the potential closure methods if the closure plans are under development and multiple closure options are being considered and evaluated on a site-by-site basis. See Note 9 for additional information.

Revenue Recognition and Unbilled Revenue

Revenues on sales of electricity and natural gas are recognized when service is provided or the product is delivered. Unbilled revenues are recognized by applying customer billing rates to the estimated volumes of energy or natural gas delivered but not yet billed. Unbilled revenues can vary significantly from period to period as a result of seasonality, weather, customer usage patterns, customer mix, average price in effect for customer classes, timing of rendering customer bills and meter reading schedules, and the impact of weather normalization or margin decoupling mechanisms.

Unbilled revenues are included within Receivables and Receivables of VIEs on the Consolidated Balance Sheets as shown in the following table.

	December 31,	
(in millions)	**2017**	**2016**
Duke Energy	**$ 944**	$ 831
Duke Energy Carolinas	**342**	313
Progress Energy	**228**	161
Duke Energy Progress	**143**	102
Duke Energy Florida	**85**	59
Duke Energy Ohio	**4**	2
Duke Energy Indiana	**21**	32
Piedmont	**86**	77

Additionally, Duke Energy Ohio and Duke Energy Indiana sell, on a revolving basis, nearly all of their retail accounts receivable, including receivables for unbilled revenues, to an affiliate, Cinergy Receivables Company LLC (CRC) and account for the transfers of receivables as sales. Accordingly, the receivables sold are not reflected on the Consolidated Balance Sheets of Duke Energy Ohio and Duke Energy Indiana. See Note 17 for further information. These receivables for unbilled revenues are shown in the table below.

	December 31,	
(in millions)	**2017**	**2016**
Duke Energy Ohio	**$ 104**	$ 97
Duke Energy Indiana	**132**	123

Allowance for Doubtful Accounts

Allowances for doubtful accounts are presented in the following table.

	December 31,		
(in millions)	**2017**	**2016**	**2015**
Allowance for Doubtful Accounts			
Duke Energy	**$ 14**	$ 14	$ 12
Duke Energy Carolinas	**2**	2	3
Progress Energy	**4**	6	6
Duke Energy Progress	**1**	4	4
Duke Energy Florida	**3**	2	2
Duke Energy Ohio	**3**	2	2
Duke Energy Indiana	**2**	1	1
Piedmont[(a)]	**2**	3	
Allowance for Doubtful Accounts – VIEs			
Duke Energy	**$ 54**	$ 54	$ 53
Duke Energy Carolinas	**7**	7	7
Progress Energy	**7**	7	8
Duke Energy Progress	**5**	5	5
Duke Energy Florida	**2**	2	3

(a) Piedmont's allowance for doubtful accounts was $2 million as of October 31, 2016, and 2015.

Derivatives and Hedging

Derivative and non-derivative instruments may be used in connection with commodity price and interest rate activities, including swaps, futures, forwards and options. All derivative instruments, except those that qualify for the normal purchase/normal sale (NPNS) exception, are recorded on the Consolidated Balance Sheets at fair value. Qualifying derivative instruments may be designated as either cash flow hedges or fair value hedges. Other derivative instruments (undesignated contracts) either have not been designated or do not qualify as hedges. The effective portion of the change in the fair value of cash flow hedges is recorded in AOCI. The effective portion of the change in the fair value of a fair value hedge is offset in net income by changes in the hedged item. For activity subject to regulatory accounting, gains and losses on derivative contracts are reflected as regulatory assets or liabilities and not as other comprehensive income or current period income. As a result, changes in fair value of these derivatives have no immediate earnings impact.

Formal documentation, including transaction type and risk management strategy, is maintained for all contracts accounted for as a hedge. At inception and at least every three months thereafter, the hedge contract is assessed to see if it is highly effective in offsetting changes in cash flows or fair values of hedged items.

See Note 14 for further information.

Captive Insurance Reserves

Duke Energy has captive insurance subsidiaries that provide coverage, on an indemnity basis, to the Subsidiary Registrants as well as certain third parties, on a limited basis, for financial losses, primarily related to property, workers’ compensation and general liability. Liabilities include provisions for estimated losses incurred but not yet reported (IBNR), as well as estimated provisions for known claims. IBNR reserve estimates are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from experience.

Duke Energy, through its captive insurance entities, also has reinsurance coverage with third parties for certain losses above a per occurrence and/or aggregate retention. Receivables for reinsurance coverage are recognized when realization is deemed probable.

Unamortized Debt Premium, Discount and Expense

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the term of the debt issue. The gain or loss on extinguishment associated with refinancing higher-cost debt obligations in the regulated operations is amortized. Amortization expense is recorded as Interest Expense in the Consolidated Statements of Operations and is reflected as Depreciation, amortization and accretion within Net cash provided by operating activities on the Consolidated Statements of Cash Flows.

Premiums, discounts and expenses are presented as an adjustment to the carrying value of the debt amount and included in Long-Term Debt on the Consolidated Balance Sheets presented.

Loss Contingencies and Environmental Liabilities

Contingent losses are recorded when it is probable a loss has occurred and can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, the minimum amount in the range is recorded. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental liabilities are recorded on an undiscounted basis when environmental remediation or other liabilities become probable and can be reasonably estimated. Environmental expenditures related to past operations that do not generate current or future revenues are expensed. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Certain environmental expenditures receive regulatory accounting treatment and are recorded as regulatory assets.

See Notes 4 and 5 for further information.

Pension and Other Post-Retirement Benefit Plans

Duke Energy maintains qualified, non-qualified and other post-retirement benefit plans. Eligible employees of the Subsidiary Registrants participate in the respective qualified, non-qualified and other post-retirement benefit plans and the Subsidiary Registrants are allocated their proportionate share of benefit costs. See Note 21 for further information, including significant accounting policies associated with these plans.

Severance and Special Termination Benefits

Duke Energy has severance plans under which, in general, the longer a terminated employee worked prior to termination the greater the amount of severance benefits. A liability for involuntary severance is recorded once an involuntary severance plan is committed to by management if involuntary severances are probable and can be reasonably estimated. For involuntary severance benefits incremental to its ongoing severance plan benefits, the fair value of the obligation is expensed at the communication date if there are no future service requirements or over the required future service period. From time to time, Duke Energy offers special termination benefits under voluntary severance programs. Special termination benefits are recorded immediately upon employee acceptance absent a significant retention period. Otherwise, the cost is recorded over the remaining service period. Employee acceptance of voluntary severance benefits is determined by management based on the facts and circumstances of the benefits being offered. See Note 19 for further information.

Guarantees

If necessary, liabilities are recognized at the time of issuance or material modification of a guarantee for the estimated fair value of the obligation it assumes. Fair value is estimated using a probability-weighted approach. The obligation is reduced over the term of the guarantee or related contract in a systematic and rational method as risk is reduced. Any additional contingent loss for guarantee contracts subsequent to the initial recognition of a liability is accounted for and recognized at the time a loss is probable and can be reasonably estimated. See Note 7 for further information.

Stock-Based Compensation

Stock-based compensation represents costs related to stock-based awards granted to employees and Duke Energy Board of Directors (Board of Directors) members. Duke Energy recognizes stock-based compensation based upon the estimated fair value of awards, net of estimated forfeitures at the date of issuance. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period. Compensation cost is recognized as expense or capitalized as a component of property, plant and equipment. See Note 20 for further information.

Income Taxes

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns. The Subsidiary Registrants are parties to a tax-sharing agreement with Duke Energy. Income taxes recorded represent amounts the Subsidiary Registrants would incur as separate C-Corporations. Deferred income taxes have been provided for temporary differences between GAAP and tax bases of assets and liabilities because the differences create taxable or tax-deductible amounts for future periods. Investment tax credits (ITCs) associated with regulated operations are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties.

Accumulated deferred income taxes are valued using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax asset or liability is expected to be settled or realized. In the event of a change in tax rates, deferred tax assets and liabilities are remeasured as of the enactment date of the new rate. To the extent that the change in the value of the deferred tax represents an obligation to customers, the impact of the remeasurement is deferred to a regulatory liability. Remaining impacts are recorded in income from continuing operations. Other impacts of the Tax Act have been recorded on a provisional basis, see Note 22, “Income Taxes,” for additional information. If Duke Energy's estimate of the tax effect of reversing temporary differences is not reflective of actual outcomes, is modified to reflect new developments or interpretations of the tax law, revised to incorporate new accounting principles, or changes in the expected timing or manner of the reversal then Duke Energy's results of operations could be impacted.

Tax-related interest and penalties are recorded in Interest Expense and Other Income and Expenses, net in the Consolidated Statements of Operations.

See Note 22 for further information.

Accounting for Renewable Energy Tax Credits

When Duke Energy receives ITCs on wind or solar facilities, it reduces the basis of the property recorded on the Consolidated Balance Sheets by the amount of the ITC and, therefore, the ITC benefit is ultimately recognized in the statement of operations through reduced depreciation expense. Additionally, certain tax credits and government grants result in an initial tax depreciable base in excess of the book carrying value by an amount equal to one half of the ITC. Deferred tax benefits are recorded as a reduction to income tax expense in the period that the basis difference is created.

Excise Taxes

Certain excise taxes levied by state or local governments are required to be paid even if not collected from the customer. These taxes are recognized on a gross basis. Otherwise, the taxes are accounted for net. Excise taxes accounted for on a gross basis within both Operating Revenues and Property and other taxes in the Consolidated Statements of Operations were as follows.

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Duke Energy	**$ 376**	$ 362	$ 396
Duke Energy Carolinas	**36**	31	31
Progress Energy	**220**	213	229
Duke Energy Progress	**19**	18	16
Duke Energy Florida	**201**	195	213
Duke Energy Ohio	**98**	100	102
Duke Energy Indiana	**20**	17	34
Piedmont[(a)]	**2**		

(a) Piedmont's excise taxes were immaterial for the two months ended December 31, 2016, and $2 million for the years ended October 31, 2016, and 2015.

Dividend Restrictions and Unappropriated Retained Earnings

Duke Energy does not have any legal, regulatory or other restrictions on paying common stock dividends to shareholders. However, as further described in Note 4, due to conditions established by regulators in conjunction with merger transaction approvals, Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, Duke Energy Indiana and Piedmont have restrictions on paying dividends or otherwise advancing funds to Duke Energy. At December 31, 2017, and 2016, an insignificant amount of Duke Energy's consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

The new accounting standards adopted for 2017 and 2016 had no material impact on the presentation or results of operations, cash flows or financial position of the Duke Energy Registrants. The following accounting standards were adopted by the Duke Energy Registrants during 2017.

Stock-Based Compensation and Income Taxes. In first quarter 2017, Duke Energy adopted Financial Accounting Standards Board (FASB) guidance, which revised the accounting for stock-based compensation and the associated income taxes. The adopted guidance changed certain aspects of accounting for stock-based payment awards to employees including the accounting for income taxes and classification on the Consolidated Statements of Cash Flows. The primary impact to Duke Energy as a result of implementing this guidance was a cumulative-effect adjustment to retained earnings for tax benefits not previously recognized and additional income tax expense for the 12 months ended December 31, 2017. See the Duke Energy Consolidated Statements of Changes in Equity for further information.

Goodwill Impairment. In January 2017, the FASB issued revised guidance for the subsequent measurement of goodwill. Under the guidance, a company will recognize an impairment to goodwill for the amount by which a reporting unit's carrying value exceeds the reporting unit's fair value, not to exceed the amount of goodwill allocated to that reporting unit. Duke Energy early adopted this guidance for the 2017 annual goodwill impairment test.

The following new accounting standards have been issued, but have not yet been adopted by the Duke Energy Registrants, as of December 31, 2017.

Revenue from Contracts with Customers. In May 2014, the FASB issued revised accounting guidance for revenue recognition from contracts with customers. The core principle of this guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Duke Energy has identified material revenue streams, which served as the basis for accounting analysis and documentation of the impact of this guidance on revenue recognition. The accounting analysis included reviewing representative contracts and tariffs for each material revenue stream. Most of Duke Energy's revenue will be in scope of the new guidance. The majority of our sales, including energy provided to residential customers, are from tariff offerings that provide natural gas or electricity without a defined contractual term ("at-will"). For such arrangements, revenue from contracts with customers will be equivalent to the electricity or natural gas supplied and billed in that period (including estimated billings). As such, there will not be a significant shift in the timing or pattern of revenue recognition for such sales.

Also included in the accounting analysis was the evaluation of certain long-term revenue streams including electric wholesale contracts and renewables power purchase agreements (PPAs). For such arrangements, Duke Energy does not expect material changes to the pattern of revenue recognition on the registrants. In addition, Duke Energy has monitored the activities of the power and utilities industry revenue recognition task force including draft accounting positions released in October 2017 and the impact, if any, on Duke Energy's specific contracts and conclusions. Potential revisions to processes, policies and controls, primarily related to evaluating supplemental disclosures required as a result of adopting this guidance, will be evaluated and implemented as necessary. Some revenue arrangements, such as alternative revenue programs and certain PPAs accounted for as leases, are excluded from the scope of the new revenue recognition guidance and, therefore, will be accounted for and evaluated for separate presentation and disclosure under other relevant accounting guidance.

Duke Energy intends to use the modified retrospective method of adoption effective January 1, 2018. Under the modified retrospective method of adoption, prior year reported results are not restated and a cumulative-effect adjustment, if applicable, is recorded to retained earnings at January 1, 2018, as if the standard had always been in effect. In addition, disclosures, if applicable, include a comparison to what would have been reported for 2018 under the previous revenue recognition rules to assist financial statement users in understanding how revenue recognition has changed as a result of this standard and to facilitate comparability with prior year reported results, which are not restated under the modified retrospective approach as described above. Duke Energy will utilize certain practical expedients including applying this guidance to open contracts at the date of adoption and recognizing revenues for certain contracts under the invoice practical expedient, which allows revenue recognition to be consistent with invoiced amounts (including estimated billings) provided certain criteria are met, including consideration of whether the invoiced amounts reasonably represent the value provided to customers. While the adoption of this guidance is not expected to have a material impact on either the timing or amount of revenues recognized in Duke Energy's financial statements, Duke Energy anticipates additional disclosures around the nature, amount, timing and uncertainty of our revenues and cash flows arising from contracts with customers. Duke Energy continues to evaluate what information will be most useful for users of the financial statements, including information already provided in disclosures outside of the financial statement footnotes. These additional disclosures are expected to include the disaggregation of revenues by customer class.

Financial Instruments Classification and Measurement. In January 2016, the FASB issued revised accounting guidance for the classification and measurement of financial instruments. Changes in the fair value of all equity securities will be required to be recorded in net income. Current GAAP allows some changes in fair value for available-for-sale equity securities to be recorded in AOCI. Additional disclosures will be required to present separately the financial assets and financial liabilities by measurement category and form of financial asset. An entity's equity investments that are accounted for under the equity method of accounting are not included within the scope of the new guidance.

For Duke Energy, the revised accounting guidance is effective for interim and annual periods beginning January 1, 2018, by recording a cumulative effect adjustment to retained earnings as of January 1, 2018. This guidance is expected to have minimal impact on the Duke Energy Registrant's Consolidated Statements of Operations and Comprehensive Income as changes in the fair value of most of the Duke Energy Registrants' available-for-sale equity securities are deferred as regulatory assets or liabilities pursuant to accounting guidance for regulated operations.

Leases. In February 2016, the FASB issued revised accounting guidance for leases. The core principle of this guidance is that a lessee should recognize the assets and liabilities that arise from leases on the balance sheet.

For Duke Energy, this guidance is effective for interim and annual periods beginning January 1, 2019. The guidance is applied using a modified retrospective approach. Upon adoption, Duke Energy expects to elect the practical expedients, which would require no reassessment of whether existing contracts are or contain leases as well as no reassessment of lease classification for existing leases. Additionally, we expect to adopt the optional transition practical expedient allowing the entity not to reassess the accounting for land easements that currently exist at the adoption of the lease standard on January 1, 2019. Duke Energy is currently evaluating the financial statement impact of adopting this standard and is continuing to monitor industry implementation issues, including easements, pole attachments and renewable PPAs. Other than an expected increase in assets and liabilities, the ultimate impact of the new standard has not yet been determined. Significant system enhancements, including additional processes and controls, will be required to facilitate the identification, tracking and reporting of potential leases based upon requirements of the new lease standard. Duke Energy has begun the implementation of a third-party software tool to help with the adoption and ongoing accounting under the new standard.

Statement of Cash Flows. In November 2016, the FASB issued revised accounting guidance to reduce diversity in practice for the presentation and classification of restricted cash on the statement of cash flows. Under the updated guidance, restricted cash and restricted cash equivalents will be included within beginning-of-period and end-of-period cash and cash equivalents on the statement of cash flows.

For Duke Energy, this guidance is effective for the interim and annual periods beginning January 1, 2018. The guidance will be applied using a retrospective transition method to each period presented. Upon adoption by Duke Energy, the revised guidance will result in a change to the amount of cash and cash equivalents and restricted cash explained when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. Prior to adoption, the Duke Energy Registrants reflect changes in restricted cash within Cash Flows from Investing Activities and within Cash Flows from Operating Activities on the Consolidated Statement of Cash Flows. As a result of this change, our Cash and cash equivalents balance on the Consolidated Statement of Cash Flows as of December 31, 2017 will change by $147 million.

Retirement Benefits. In March 2017, the FASB issued revised accounting guidance for the presentation of net periodic costs related to benefit plans. Current GAAP permits the aggregation of all the components of net periodic costs on the Consolidated Statement of Operations and does not require the disclosure of the location of net periodic costs on the Consolidated Statement of Operations. Under the amended guidance, the service cost component of net periodic costs must be included within Operating Income within the same line as other compensation expenses. All other components of net periodic costs must be outside of Operating Income. In addition, the updated guidance permits only the service cost component of net periodic costs to be capitalized to Inventory or Property, Plant and Equipment. This represents a change from current GAAP, which permits all components of net periodic costs to be capitalized. These amendments should be applied retrospectively for the presentation of the various components of net periodic costs and prospectively for the change in eligible costs to be capitalized. The guidance allows for a practical expedient that permits a company to use amounts disclosed in prior-period financial statements as the estimation basis for applying the retrospective presentation requirements.

For Duke Energy, this guidance is effective for interim and annual periods beginning January 1, 2018. Duke Energy currently presents the total non-capitalized net periodic costs within Operation, maintenance and other on the Consolidated Statement of Operations. The adoption of this guidance will result in a retrospective change to reclassify the presentation of the non-service cost (benefit) components of net periodic costs to Other income and expenses. Duke Energy intends to utilize the practical expedient for retrospective presentation. The change in net periodic costs eligible for capitalization is applicable prospectively. Since Duke Energy’s service cost component is expected to be greater than the total net periodic costs, the change will result in increased capitalization of net periodic costs, higher Operation, maintenance and other and higher Other income and expenses. The resulting impact to Duke Energy is expected to be an immaterial increase in Net Income resulting from the limitation of eligible capitalization of net periodic costs to the service cost component, which is larger than the total net periodic costs.

2. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

The Duke Energy Registrants consolidate assets and liabilities from acquisitions as of the purchase date and include earnings from acquisitions in consolidated earnings after the purchase date.

2016 Acquisition of Piedmont Natural Gas

On October 3, 2016, Duke Energy acquired all outstanding common stock of Piedmont for a total cash purchase price of $5.0 billion and assumed Piedmont's existing long-term debt, which had a fair value of approximately $2.0 billion at the time of the acquisition. The acquisition provides a foundation for Duke Energy to establish a broader, long-term strategic natural gas infrastructure platform to complement its existing natural gas pipeline investments and regulated natural gas business in the Midwest. In connection with the closing of the acquisition, Piedmont became a wholly owned subsidiary of Duke Energy.

Purchase Price Allocation

The purchase price allocation of the Piedmont acquisition is as follows:

(in millions)		
Current assets	$	497
Property, plant and equipment, net		4,714
Goodwill		3,353
Other long-term assets		804
Total assets		9,368
Current liabilities, including current maturities of long-term debt		576
Long-term liabilities		1,790
Long-term debt		2,002
Total liabilities		4,368
Total purchase price	$	5,000

The fair value of Piedmont's assets and liabilities was determined based on significant estimates and assumptions that are judgmental in nature, including the amount and timing of projected future cash flows, discount rates reflecting risk inherent in the future cash flows and market prices of long-term debt.

The majority of Piedmont's operations are subject to the rate-setting authority of the NCUC, the PSCSC and the TPUC and are accounted for pursuant to accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for Piedmont's regulated operations provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. Thus, the fair value of Piedmont's assets and liabilities subject to these rate-setting provisions approximates the pre-acquisition carrying values and does not reflect any net valuation adjustments.

The significant assets and liabilities for which valuation adjustments were reflected within the purchase price allocation include the acquired equity method investments and long-term debt. The difference between the fair value and the pre-merger carrying values of long-term debt for regulated operations was recorded as a regulatory asset.

The excess of the purchase price over the fair value of Piedmont's assets and liabilities on the acquisition date was recorded as goodwill. The goodwill reflects the value paid by Duke Energy primarily for establishing a broader, long-term strategic natural gas infrastructure growth platform, an improved risk profile and expected synergies resulting from the combined entities.

Under Securities and Exchange Commission (SEC) regulations, Duke Energy elected not to apply push down accounting to the stand-alone Piedmont financial statements.

Accounting Charges Related to the Acquisition

Duke Energy incurred pretax non-recurring transaction and integration costs associated with the acquisition of $103 million, $439 million and $9 million for the years ended December 31, 2017, 2016 and 2015, respectively. Amounts recorded on the Consolidated Statements of Operations in 2017 were primarily system integration costs of $71 million related to combining the various operational and financial systems of Duke Energy and Piedmont, including a one-time software impairment resulting from planned accounting system and process integration. A $7 million charge was recorded within Impairment Charges, with the remaining $64 million recorded within Operation, maintenance and other.

Amounts recorded in 2016 include:

- Interest expense of $234 million related to the acquisition financing, including realized losses on forward-starting interest rate swaps of $190 million. See Note 14 for additional information on the swaps.
- Charges of $104 million related to commitments made in conjunction with the transaction, including charitable contributions and a one-time bill credit to Piedmont customers. $10 million was recorded as a reduction in Operating Revenues, with the remaining $94 million recorded within Operation, maintenance and other.
- Other transaction and integration costs of $101 million recorded to Operation, maintenance and other, including professional fees and severance.

The majority of transition and integration activities are expected to be completed by the end of 2018.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the combined results of operations of Duke Energy and Piedmont as if the merger had occurred as of January 1, 2015. The pro forma financial information does not include potential cost savings, intercompany revenues, Piedmont's earnings from a certain equity method investment sold immediately prior to the merger or non-recurring transaction and integration costs incurred by Duke Energy and Piedmont. The after-tax non-recurring transaction and integration costs incurred by Duke Energy and Piedmont were $279 million and $19 million for the years ended December 31, 2016, and 2015, respectively.

This information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of Duke Energy.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Operating Revenues	**$ 23,504**	$ 23,570
Net Income Attributable to Duke Energy Corporation	**2,442**	2,877

Piedmont's Earnings

Piedmont's revenues and net income included in Duke Energy's Consolidated Statements of Operations for the year ended December 31, 2016, were $367 million and $20 million, respectively. Piedmont's revenues and net income for the year ended December 31, 2016, include the impact of non-recurring transaction costs of $10 million and $46 million, respectively.

Acquisition Related Financings and Other Matters

Duke Energy financed the Piedmont acquisition with a combination of debt and equity issuances and other cash sources, including:

- $3.75 billion of long-term debt issued in August 2016.
- $750 million borrowed under the $1.5 billion short-term loan facility in September 2016, which was repaid in December 2016.
- 10.6 million shares of common stock issued in October 2016 for net cash proceeds of approximately $723 million.

The $4.9 billion senior unsecured bridge financing facility (Bridge Facility) with Barclays Capital, Inc. (Barclays) was terminated following the issuance of the long-term debt. For additional information related to the debt and equity issuances, see Notes 6 and 18, respectively. For additional information regarding Duke Energy's and Piedmont's joint investment in Atlantic Coast Pipeline, LLC (ACP), see Note 4.

DISPOSITIONS

For the year ended December 31, 2017, the Loss from Discontinued Operations, net of tax, was immaterial. The following table summarizes the (Loss) Income from Discontinued Operations, net of tax recorded on Duke Energy's Consolidated Statements of Operations for the years ended December 31, 2016, and 2015:

	Years Ended December 31,	
(in millions)	**2016**	**2015**
International Energy Disposal Group	$ (534)	$ 157
Midwest Generation Disposal Group	36	33
Other[(a)]	90	(13)
(Loss) Income from Discontinued Operations, net of tax	$ (408)	$ 177

(a) Relates to previously sold businesses not related to the Disposal Groups. The amount for 2016 represents an income tax benefit resulting from immaterial out of period deferred tax liability adjustments. The amount for 2015 includes indemnifications provided for certain legal, tax and environmental matters and foreign currency translation adjustments.

2016 Sale of International Energy

In February 2016, Duke Energy announced it had initiated a process to divest its International Energy businesses, excluding the equity method investment in NMC (the International Disposal Group), and in October 2016, announced it had entered into two separate purchase and sale agreements to execute the divestiture. Both sales closed in December of 2016, resulting in available cash proceeds of $1.9 billion, excluding transaction costs. Proceeds were primarily used to reduce Duke Energy holding company (the parent) debt. Existing favorable tax attributes result in no immediate U.S. federal-level cash tax impacts. Details of each transaction are as follows:

- On December 20, 2016, Duke Energy closed on the sale of its ownership interests in businesses in Argentina, Chile, Ecuador, El Salvador, Guatemala and Peru to I Squared Capital. The assets sold included approximately 2,230 MW of hydroelectric and natural gas generation capacity, transmission infrastructure and natural gas processing facilities. I Squared Capital purchased the businesses for an enterprise value of $1.2 billion.
- On December 29, 2016, Duke Energy closed on the sale of its Brazilian business, which included approximately 2,090 MW of hydroelectric generation capacity, to CTG for an enterprise value of $1.2 billion. With the closing of the CTG deal, Duke Energy finalized its exit from the Latin American market.

Assets Held For Sale and Discontinued Operations

As a result of the transactions, the International Disposal Group was classified as held for sale and as discontinued operations in the fourth quarter of 2016. Interest expense directly associated with the International Disposal Group was allocated to discontinued operations. No interest from corporate level debt was allocated to discontinued operations.

The following table presents the results of the International Disposal Group for the years ended December 31, 2016, and 2015, which are included in (Loss) Income from Discontinued Operations, net of tax in Duke Energy's Consolidated Statements of Operations.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Operating Revenues	$ 988	$ 1,088
Fuel used in electric generation and purchased power	227	306
Cost of natural gas	43	53
Operation, maintenance and other	341	334
Depreciation and amortization[(a)]	62	92
Property and other taxes	15	7
Impairment charges [(b)]	194	13
(Loss) Gains on Sales of Other Assets and Other, net	(3)	6
Other Income and Expenses, net	58	23
Interest Expense	82	85
Pretax loss on disposal[(c)]	(514)	—
(Loss) Income before income taxes[(d)]	(435)	227
Income tax expense[(e)(f)]	99	70
(Loss) Income from discontinued operations of the International Disposal Group	$ (534)	$ 157

(a) Upon meeting the criteria for assets held for sale, beginning in the fourth quarter of 2016 depreciation expense was ceased.

(b) In conjunction with the advancements of marketing efforts during 2016, Duke Energy performed recoverability tests of the long-lived asset groups of International Energy. As a result, Duke Energy determined the carrying value of certain assets in Central America was not fully recoverable and recorded a pretax impairment charge of $194 million. The charge represents the excess of carrying value over the estimated fair value of the assets, which was based on a Level 3 Fair Value measurement that was primarily determined from the income approach using discounted cash flows but also considered market information obtained in 2016.

(c) The pretax loss on disposal includes the recognition of cumulative foreign currency translation losses of $620 million as of the disposal date. See the Consolidated Statements of Changes in Equity for additional information.

(d) Pretax (Loss) Income attributable to Duke Energy Corporation was $(445) million and $221 million for the years ended December 31, 2016 and 2015, respectively.

(e) 2016 amount includes $126 million of income tax expense on the disposal, which primarily reflects in-country taxes incurred as a result of the sale. The after-tax loss on disposal was $640 million.

(f) 2016 amount includes an income tax benefit of $95 million. See Note 22, "Income Taxes," for additional information.

Duke Energy has elected not to separately disclose discontinued operations on the Consolidated Statements of Cash Flows. The following table summarizes Duke Energy's cash flows from discontinued operations related to the International Disposal Group.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Cash flows provided by (used in):		
Operating activities	**$ 204**	$ 248
Investing activities	**(434)**	177

Other Sale Related Matters

During 2017, Duke Energy provided certain transition services to CTG and I Squared Capital. Cash flows related to providing the transition services were not material as of December 31, 2017. All transition services related to the International Disposal Group ended in 2017. Additionally, Duke Energy will reimburse CTG and I Squared Capital for all tax obligations arising from the period preceding consummation on the transactions, totaling approximately $78 million. Duke Energy has not recorded any other liabilities, contingent liabilities or indemnifications related to the International Disposal Group.

2015 Midwest Generation Exit

Duke Energy, through indirect subsidiaries, completed the sale of the Midwest Generation Disposal Group to a subsidiary of Dynegy on April 2, 2015, for approximately $2.8 billion in cash. The nonregulated Midwest generation business included generation facilities with approximately 5,900 MW of owned capacity located in Ohio, Pennsylvania and Illinois. On April 1, 2015, prior to the sale, Duke Energy Ohio distributed its indirect ownership interest in the nonregulated Midwest generation business to a subsidiary of Duke Energy Corporation.

Duke Energy utilized a revolving credit agreement (RCA) to support the operations of the nonregulated Midwest generation business. Duke Energy Ohio had a power purchase agreement with the Midwest Generation Disposal Group for a portion of its standard service offer (SSO) supply requirement. The agreement and the SSO expired in May 2015.

The results of operations of the Midwest Generation Disposal Group prior to the date of sale are classified as discontinued operations in the accompanying Consolidated Statements of Operations. Interest expense associated with the RCA was allocated to discontinued operations. No other interest expense related to corporate level debt was allocated to discontinued operations. Certain immaterial costs that were eliminated as a result of the sale remained in continuing operations. The following table summarizes the Midwest Generation Disposal Group activity recorded within discontinued operations.

	Duke Energy		Duke Energy Ohio	
	Years Ended December 31,		Years Ended December 31,	
(in millions)	**2016**	**2015**	**2016**	**2015**
Operating Revenues	$ —	$ 543	$ —	$ 412
Pretax Loss on disposal[a]	—	(45)	—	(52)
Income (loss) before income taxes[b]	$ —	$ 59	$ —	$ 44
Income tax (benefit) expense[c]	(36)	26	(36)	21
Income (loss) from discontinued operations	$ 36	$ 33	$ 36	$ 23

(a) The Loss on disposal includes impairments recorded to adjust the carrying amount of the assets to the estimated fair value of the business, based on the selling price to Dynegy less cost to sell.
(b) 2015 amounts include the impact of an $81 million charge for the settlement agreement reached in a lawsuit related to the Midwest Generation Disposal Group. Refer to Note 5 for further information about the lawsuit.
(c) 2016 amounts result from immaterial out of period deferred tax liability adjustments.

3. BUSINESS SEGMENTS

Operating segments are determined based on information used by the chief operating decision-maker in deciding how to allocate resources and evaluate the performance of the business. Duke Energy evaluates segment performance based on segment income. Segment income is defined as income from continuing operations net of income attributable to noncontrolling interests. Segment income, as discussed below, includes intercompany revenues and expenses that are eliminated on the Consolidated Financial Statements. Certain governance costs are allocated to each segment. In addition, direct interest expense and income taxes are included in segment income.

Products and services are sold between affiliate companies and reportable segments of Duke Energy at cost. Segment assets as presented in the tables that follow exclude all intercompany assets.

Duke Energy

Duke Energy's segment structure includes the following segments: Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

The Electric Utilities and Infrastructure segment includes Duke Energy's regulated electric utilities in the Carolinas, Florida and the Midwest. The regulated electric utilities conduct operations through the Subsidiary Registrants that are substantially all regulated and, accordingly, qualify for regulatory accounting treatment. Electric Utilities and Infrastructure also includes Duke Energy's commercial electric transmission infrastructure investments.

The Gas Utilities and Infrastructure segment includes Piedmont, Duke Energy's natural gas local distribution companies in Ohio and Kentucky, and Duke Energy's natural gas storage and midstream pipeline investments. Gas Utilities and Infrastructure's operations are substantially all regulated and, accordingly, qualify for regulatory accounting treatment.

The Commercial Renewables segment is primarily comprised of nonregulated utility scale wind and solar generation assets located throughout the U.S.

The remainder of Duke Energy’s operations is presented as Other, which is primarily comprised of corporate interest expense, unallocated corporate costs, contributions to the Duke Energy Foundation and the operations of Duke Energy’s wholly owned captive insurance subsidiary, Bison Insurance Company Limited (Bison). Other also includes Duke Energy's interest in NMC. See Note 12 for additional information on the investment in NMC.

Business segment information is presented in the following tables. Segment assets presented exclude intercompany assets.

	Year Ended December 31, 2017						
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Commercial Renewables**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Unaffiliated Revenues	$ 21,300	$ 1,743	$ 460	$ 23,503	$ 62	$ —	$ 23,565
Intersegment Revenues	31	93	—	124	76	(200)	—
Total Revenues	$ 21,331	$ 1,836	$ 460	$ 23,627	$ 138	$ (200)	$ 23,565

Interest Expense	**$ 1,240**	**$ 105**	**$ 87**	**$ 1,432**	**$ 574**	**$ (20)**	**$ 1,986**
Depreciation and amortization	**3,010**	**231**	**155**	**3,396**	**131**	**—**	**3,527**
Equity in earnings (losses) of unconsolidated affiliates	**5**	**62**	**(5)**	**62**	**57**	**—**	**119**
Income tax expense (benefit)[a]	**1,355**	**116**	**(628)**	**843**	**353**	**—**	**1,196**
Segment income (loss)[b][c][d]	**3,210**	**319**	**441**	**3,970**	**(905)**	**—**	**3,065**
Add back noncontrolling interest component							**5**
Loss from discontinued operations, net of tax							**(6)**
Net income							**$ 3,064**
Capital investments expenditures and acquisitions	**$ 7,024**	**$ 907**	**$ 92**	**$ 8,023**	**$ 175**	**$ —**	**$ 8,198**
Segment assets	**119,423**	**11,462**	**4,156**	**135,041**	**2,685**	**188**	**137,914**

(a) All segments include impacts of the Tax Cuts and Jobs Act (the Tax Act). Electric Utilities and Infrastructure includes a $231 million benefit, Gas Utilities and Infrastructure includes a $26 million benefit, Commercial Renewables includes a $442 million benefit and Other includes charges of $597 million.

(b) Electric Utilities and Infrastructure includes after-tax regulatory settlement charges of $98 million. See Note 4 for additional information.

(c) Commercial Renewables includes after-tax impairment charges of $74 million related to certain wind projects and the Energy Management Solutions reporting unit. See Notes 10 and 11 for additional information.

(d) Other includes $64 million of after-tax costs to achieve the Piedmont merger. See Note 2 for additional information.

	Year Ended December 31, 2016						
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Commercial Renewables**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Unaffiliated Revenues	$ 21,336	$ 875	$ 484	$ 22,695	$ 48	$ —	$ 22,743
Intersegment Revenues	30	26	—	56	69	(125)	—
Total Revenues	$ 21,366	$ 901	$ 484	$ 22,751	$ 117	$ (125)	$ 22,743
Interest Expense	$ 1,136	$ 46	$ 53	$ 1,235	$ 693	$ (12)	$ 1,916
Depreciation and amortization	2,897	115	130	3,142	152	—	3,294
Equity in earnings (losses) of							

unconsolidated affiliates[a]	5	19	(82)	(58)	43	—	(15)
Income tax expense (benefit)	1,672	90	(160)	1,602	(446)	—	1,156
Segment income (loss)[b][c]	3,040	152	23	3,215	(645)	1	2,571
Add back noncontrolling interest component							7
Loss from discontinued operations, net of tax[d]							(408)
Net income							$ 2,170
Capital investments expenditures and acquisitions[e]	$ 6,649	$ 5,519	$ 857	$ 13,025	$ 190	$ —	$ 13,215
Segment assets	114,993	10,760	4,377	130,130	2,443	188	132,761

(a) Commercial Renewables includes a pretax impairment charge of $71 million. See Note 12 for additional information.

(b) Other includes $329 million of after-tax costs to achieve mergers. Refer to Note 2 for additional information on costs related to the Piedmont merger.

(c) Other includes after-tax charges of $57 million related to cost savings initiatives. Refer to Note 19 for further information.

(d) Includes a loss on sale of the International Disposal Group. Refer to Note 2 for further information.

(e) Other includes $26 million of capital investments expenditures related to the International Disposal Group. Gas Utilities and Infrastructure includes the Piedmont acquisition of $5 billion. Refer to Note 2 for more information on the Piedmont acquisition.

	Year Ended December 31, 2015						
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Commercial Renewables**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Unaffiliated Revenues	$ 21,489	$ 536	$ 286	$ 22,311	$ 60	$ —	$ 22,371
Intersegment Revenues	32	5	—	37	75	(112)	—
Total Revenues	$ 21,521	$ 541	$ 286	$ 22,348	$ 135	$ (112)	$ 22,371
Interest Expense	$ 1,074	$ 25	$ 44	$ 1,143	$ 393	$ (9)	$ 1,527
Depreciation and amortization	2,735	79	104	2,918	135	—	3,053
Equity in (losses) earnings of unconsolidated affiliates	(2)	1	(6)	(7)	76	—	69

Income tax expense (benefit)	1,602	44	(128)	1,518	(262)	—	1,256
Segment income (loss) [a][b][c]	2,819	73	52	2,944	(299)	—	2,645
Add back noncontrolling interest component							9
Income from discontinued operations, net of tax[d]							177
Net income							$ 2,831
Capital investments expenditures and acquisitions[e]	$ 6,852	$ 234	$ 1,019	$ 8,105	$ 258	$ —	$ 8,363
Segment assets[f]	109,097	2,637	3,861	115,595	5,373	188	121,156

(a) Electric Utilities and Infrastructure includes an after-tax charge of $58 million related to the Edwardsport settlement. Refer to Note 4 for further information.
(b) Other includes $60 million of after-tax costs to achieve mergers.
(c) Other includes after-tax charges of $77 million related to cost savings initiatives. Refer to Note 19 for further information.
(d) Includes the impact of a settlement agreement reached in a lawsuit related to the Midwest Generation Disposal Group. Refer to Note 5 for further information related to the lawsuit and Note 2 for further information on discontinued operations.
(e) Other includes capital investment expenditures of $45 million related to the International Disposal Group.
(f) Other includes Assets Held for Sale balances related to the International Disposal Group. Refer to Note 2 for further information.

Geographical Information

For the years ended December 31, 2017, 2016 and 2015, all assets and revenues from continuing operations are within the U.S.

Major Customers

For the year ended December 31, 2017, revenues from one customer of Duke Energy Progress are $521 million. Duke Energy Progress has one reportable segment, Electric Utilities and Infrastructure. No other subsidiary registrant has an individual customer representing more than 10 percent of its revenues.

Products and Services

The following table summarizes revenues of the reportable segments by type.

(in millions)	Retail Electric	Wholesale Electric	Retail Natural Gas	Other	Total Revenues
2017					
Electric Utilities and Infrastructure	**$ 18,177**	**$ 2,104**	**$ —**	**$ 1,050**	**$ 21,331**
Gas Utilities and Infrastructure	**—**	**—**	**1,732**	**104**	**1,836**
Commercial Renewables	**—**	**375**	**—**	**85**	**460**
Total Reportable Segments	**$ 18,177**	**$ 2,479**	**$ 1,732**	**$ 1,239**	**$ 23,627**
2016					
Electric Utilities and Infrastructure	$ 18,338	$ 2,095	$ —	$ 933	$ 21,366
Gas Utilities and Infrastructure	—	—	871	30	901
Commercial Renewables	—	303	—	181	484

Total Reportable Segments	$ 18,338	$ 2,398	$ 871	$ 1,144	$ 22,751
2015					
Electric Utilities and Infrastructure	$ 18,695	$ 2,014	$ —	$ 812	$ 21,521
Gas Utilities and Infrastructure	—	—	546	(5)	541
Commercial Renewables	—	245	—	41	286
Total Reportable Segments	$ 18,695	$ 2,259	$ 546	$ 848	$ 22,348

Duke Energy Ohio

Duke Energy Ohio has two reportable operating segments, Electric Utilities and Infrastructure and Gas Utilities and Infrastructure.

Electric Utilities and Infrastructure transmits and distributes electricity in portions of Ohio and generates, distributes and sells electricity in portions of Northern Kentucky. Gas Utilities and Infrastructure transports and sells natural gas in portions of Ohio and Northern Kentucky. It conducts operations primarily through Duke Energy Ohio and its wholly owned subsidiary, Duke Energy Kentucky.

The remainder of Duke Energy Ohio's operations is presented as Other, which is primarily comprised of governance costs allocated by its parent, Duke Energy, and revenues and expenses related to Duke Energy Ohio's contractual arrangement to buy power from OVEC's (Ohio Valley Electric Corporation) power plants. See Note 13 for additional information on related party transactions. For the years ended December 31, 2017, 2016 and 2015, all Duke Energy Ohio assets and revenues are within the U.S.

	Year Ended December 31, 2017					
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Total revenues	**$ 1,373**	**$ 508**	**$ 1,881**	**$ 42**	**$ —**	**$ 1,923**
Interest expense	**$ 62**	**$ 28**	**$ 90**	**$ 1**	**$ —**	**$ 91**
Depreciation and amortization	**178**	**83**	**261**	**$ —**	**—**	**261**
Income tax expense (benefit)	**40**	**39**	**79**	**$ (20)**	**—**	**59**
Segment income (loss)	**138**	**85**	**223**	**$ (30)**	**—**	**193**
Loss from discontinued operations, net of tax						**(1)**
Net income						**$ 192**
Capital expenditures	**$ 491**	**$ 195**	**$ 686**	**$ —**	**$ —**	**$ 686**
Segment assets	**5,066**	**2,758**	**7,824**	**66**	**(15)**	**7,875**

	Year Ended December 31, 2016					
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Total revenues	$ 1,410	$ 503	$ 1,913	$ 31	$ —	$ 1,944
Interest expense	$ 58	$ 27	$ 85	$ 1	$ —	$ 86
Depreciation and amortization	151	80	231	2	—	233
Income tax expense (benefit)	55	44	99	(21)	—	78
Segment income (loss)	154	77	231	(39)	—	192
Income from discontinued operations, net of tax						36
Net income						$ 228
Capital expenditures	$ 322	$ 154	$ 476	$ —	$ —	$ 476
Segment assets	4,782	2,696	7,478	62	(12)	7,528

	Year Ended December 31, 2015					
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Total revenues	$ 1,331	$ 541	$ 1,872	$ 33	$ —	$ 1,905
Interest expense	$ 53	$ 25	$ 78	$ 1	$ —	$ 79
Depreciation and amortization	147	79	226	1	—	227
Income tax expense (benefit)	59	45	104	(23)	—	81
Segment income (loss)	118	73	191	(41)	(1)	149
Income from discontinued operations, net of tax						23
Net income						$ 172
Capital expenditures	$ 264	$ 135	$ 399	$ —	$ —	$ 399
Segment assets	4,534	2,516	7,050	56	(9)	7,097

4. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

The Duke Energy Registrants record regulatory assets and liabilities that result from the ratemaking process. See Note 1 for further information.

The following tables present the regulatory assets and liabilities recorded on the Consolidated Balance Sheets of Duke Energy and Progress Energy. See separate tables below for balances by individual registrant.

	Duke Energy		Progress Energy	
	December 31,		December 31,	
(in millions)	2017	2016	2017	2016
Regulatory Assets				
AROs – coal ash	$ **4,025**	$ 3,761	$ **1,984**	$ 1,830
AROs – nuclear and other	**852**	684	**655**	569
Accrued pension and OPEB	**2,249**	2,387	**906**	882
Retired generation facilities	**480**	534	**386**	422
Debt fair value adjustment	**1,197**	1,313	**—**	—
Net regulatory asset related to income taxes	**—**	894	**—**	231
Storm cost deferrals	**531**	153	**526**	148
Nuclear asset securitized balance, net	**1,142**	1,193	**1,142**	1,193
Hedge costs deferrals	**234**	217	**94**	91
Derivatives – natural gas supply contracts	**142**	187	**—**	—
Demand side management (DSM)/Energy efficiency (EE)	**530**	407	**281**	278
Grid modernization	**39**	65	**—**	—
Vacation accrual	**213**	196	**42**	38
Deferred fuel and purchased power	**507**	156	**349**	111
Nuclear deferral	**119**	226	**35**	134
Post-in-service carrying costs (PISCC) and deferred operating expenses	**366**	413	**38**	42
Transmission expansion obligation	**46**	71	**—**	—
Manufactured gas plant (MGP)	**91**	99	**—**	—
Advanced metering infrastructure (AMI)	**362**	218	**150**	—
NCEMPA deferrals	**53**	51	**53**	51
East Bend deferrals	**45**	32	**—**	—
Deferred pipeline integrity costs	**54**	36	**—**	—

Amounts due from customers		**64**		66		**—**		—
Other		**538**		542		**110**		103
Total regulatory assets		**13,879**		13,901		**6,751**		6,123
Less: current portion		**1,437**		1,023		**741**		401
Total noncurrent regulatory assets	**$**	**12,442**	$	12,878	**$**	**6,010**	$	5,722
Regulatory Liabilities								
Costs of removal	**$**	**5,968**	$	5,613	**$**	**2,537**	$	2,198
ARO – nuclear and other		**806**		461		**—**		—
Net regulatory liability related to income taxes		**8,113**		—		**2,802**		—
Amounts to be refunded to customers		**10**		45		**—**		—
Storm reserve		**20**		83		**—**		60
Accrued pension and OPEB		**146**		174		**—**		—
Deferred fuel and purchased power		**47**		192		**1**		81
Other		**622**		722		**179**		245
Total regulatory liabilities		**15,732**		7,290		**5,519**		2,584
Less: current portion		**402**		409		**213**		189
Total noncurrent regulatory liabilities	**$**	**15,330**	$	6,881	**$**	**5,306**	$	2,395

Descriptions of regulatory assets and liabilities summarized in the tables above and below follow. See tables below for recovery and amortization periods at the separate registrants.

AROs – coal ash. Represents deferred depreciation and accretion related to the legal obligation to close ash basins. The costs are deferred until recovery treatment has been determined. See Notes 1 and 9 for additional information.

AROs – nuclear and other. Represents regulatory assets or liabilities, including deferred depreciation and accretion, related to legal obligations associated with the future retirement of property, plant and equipment, excluding amounts related to coal ash. The AROs relate primarily to decommissioning nuclear power facilities. The amounts also include certain deferred gains and losses on NDTF investments. See Notes 1 and 9 for additional information.

Accrued pension and OPEB. Accrued pension and other post-retirement benefit obligations (OPEB) represent regulatory assets and liabilities related to each of the Duke Energy Registrants' respective shares of unrecognized actuarial gains and losses and unrecognized prior service cost and credit attributable to Duke Energy's pension plans and OPEB plans. The regulatory asset or liability is amortized with the recognition of actuarial gains and losses and prior service cost and credit to net periodic benefit costs for pension and OPEB plans. The accrued pension and OPEB regulatory asset is expected to be recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

Retired generation facilities. Represents amounts to be recovered for facilities that have been retired and are probable of recovery.

Debt fair value adjustment. Purchase accounting adjustments recorded to state the carrying value of Progress Energy and Piedmont at fair value in connection with the 2012 and 2016 mergers, respectively. Amount is amortized over the life of the related debt.

Net regulatory asset or liability related to income taxes. Amounts for all registrants include regulatory liabilities related primarily to impacts from the Tax Act. See Note 22 for additional information. Amounts have no immediate impact on rate base as regulatory assets are offset by deferred tax liabilities.

Storm cost deferrals. Represents deferred incremental costs incurred related to extraordinary weather-related events.

Nuclear asset securitized balance, net. Represents the balance associated with Crystal River Unit 3 retirement approved for recovery by the FPSC on September 15, 2015, and the upfront financing costs securitized in 2016 with issuance of the associated bonds. The regulatory asset balance is net of the AFUDC equity portion.

Hedge costs and other deferrals. Amounts relate to unrealized gains and losses on derivatives recorded as a regulatory asset or liability, respectively, until the contracts are settled.

Derivatives – natural gas supply contracts. Represents costs for certain long-dated, fixed quantity forward gas supply contracts, which are recoverable through PGA clauses.

DSM/EE. Deferred costs related to various DSM and EE programs recoverable through various mechanisms.

Grid modernization. Amounts represent deferred depreciation and operating expenses as well as carrying costs on the portion of capital expenditures placed in service but not yet reflected in retail rates as plant in service.

Vacation accrual. Generally recovered within one year.

Deferred fuel and purchased power. Represents certain energy-related costs that are recoverable or refundable as approved by the applicable regulatory body.

Nuclear deferral. Includes amounts related to levelizing nuclear plant outage costs, which allows for the recognition of nuclear outage expenses over the refueling cycle rather than when the outage occurs, resulting in the deferral of operations and maintenance costs associated with refueling.

Post-in-service carrying costs and deferred operating expenses. Represents deferred depreciation and operating expenses as well as carrying costs on the portion of capital expenditures placed in service but not yet reflected in retail rates as plant in service.

Gasification services agreement buyout. The IURC authorized Duke Energy Indiana to recover costs incurred to buy out a gasification services agreement, including carrying costs through 2017.

Transmission expansion obligation. Represents transmission expansion obligations related to Duke Energy Ohio's withdrawal from Midcontinent Independent System Operator, Inc. (MISO).

MGP. Represents remediation costs incurred at former MGP sites and the deferral of costs to be incurred at the East End and West End sites through 2019.

AMI. Represents deferred costs related to the installation of AMI meters and remaining net book value of non-AMI meters to be replaced at Duke Energy Carolinas, net book value of existing meters at Duke Energy Florida, Duke Energy Progress and Duke Energy Ohio and expected future recovery of net book value of electromechanical meters that have been replaced with AMI meters at Duke Energy Indiana.

NCEMPA deferrals. Represents retail allocated cost deferrals and returns associated with the additional ownership interest in assets acquired from NCEMPA in 2015.

East Bend deferrals. Represents both deferred operating expenses and deferred depreciation as well as carrying costs on the portion of East Bend Generating Station (East Bend) that was acquired from Dayton Power and Light and that had been previously operated as a jointly owned facility.

Deferred pipeline integrity costs. Represents pipeline integrity management costs in compliance with federal regulations recovered through a rider mechanism.

Amounts due from customers. Relates primarily to margin decoupling and IMR recovery mechanisms.

Costs of removal. Represents funds received from customers to cover the future removal of property, plant and equipment from retired or abandoned sites as property is retired. Also includes certain deferred gains on NDTF investments.

Amounts to be refunded to customers. Represents required rate reductions to retail customers by the applicable regulatory body.

Storm reserve. Amounts are used to offset future incurred costs for named storms as approved by regulatory commissions.

RESTRICTIONS ON THE ABILITY OF CERTAIN SUBSIDIARIES TO MAKE DIVIDENDS, ADVANCES AND LOANS TO DUKE ENERGY

As a condition to the approval of merger transactions, the NCUC, PSCSC, PUCO, KPSC and IURC imposed conditions on the ability of Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, Duke Energy Kentucky, Duke Energy Indiana and Piedmont to transfer funds to Duke Energy through loans or advances, as well as restricted amounts available to pay dividends to Duke Energy. Certain subsidiaries may transfer funds to the parent by obtaining approval of the respective state regulatory commissions. These conditions imposed restrictions on the ability of the public utility subsidiaries to pay cash dividends as discussed below.

Duke Energy Progress and Duke Energy Florida also have restrictions imposed by their first mortgage bond indentures, which, in certain circumstances, limit their ability to make cash dividends or distributions on common stock. Amounts restricted as a result of these provisions were not material at December 31, 2017.

Additionally, certain other subsidiaries of Duke Energy have restrictions on their ability to dividend, loan or advance funds to Duke Energy due to specific legal or regulatory restrictions, including, but not limited to, minimum working capital and tangible net worth requirements.

The restrictions discussed below were less than 25 percent of Duke Energy's and Progress Energy's net assets at December 31, 2017.

Duke Energy Carolinas

Duke Energy Carolinas must limit cumulative distributions subsequent to mergers to (i) the amount of retained earnings on the day prior to the closing of the mergers, plus (ii) any future earnings recorded.

Duke Energy Progress

Duke Energy Progress must limit cumulative distributions subsequent to the mergers between Duke Energy and Progress Energy and Duke Energy and Piedmont to (i) the amount of retained earnings on the day prior to the closing of the respective mergers, plus (ii) any future earnings recorded.

Duke Energy Ohio

Duke Energy Ohio will not declare and pay dividends out of capital or unearned surplus without the prior authorization of the PUCO. Duke Energy Ohio received FERC and PUCO approval to pay dividends from its equity accounts that are reflective of the amount that it would have in its retained earnings account had push-down accounting for the Cinergy Corp. (Cinergy) merger not been applied to Duke Energy Ohio's balance sheet. The conditions include a commitment from Duke Energy Ohio that equity, adjusted to remove the impacts of push-down accounting, will not fall below 30 percent of total capital.

Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35 percent equity in its capital structure.

Duke Energy Indiana

Duke Energy Indiana must limit cumulative distributions subsequent to the merger between Duke Energy and Cinergy to (i) the amount of retained earnings on the day prior to the closing of the merger, plus (ii) any future earnings recorded. In addition, Duke Energy Indiana will not declare and pay dividends out of capital or unearned surplus without prior authorization of the IURC.

Piedmont

Piedmont must limit cumulative distributions subsequent to the acquisition of Piedmont by Duke Energy to (i) the amount of retained earnings on the day prior to the closing of the merger, plus (ii) any future earnings recorded.

RATE RELATED INFORMATION

The NCUC, PSCSC, FPSC, IURC, PUCO, TPUC and KPSC approve rates for retail electric and natural gas services within their states. The FERC approves rates for electric sales to wholesale customers served under cost-based rates (excluding Ohio and Indiana), as well as sales of transmission service. The FERC also regulates certification and siting of new interstate natural gas pipeline projects.

All Registrants

Tax Act Impacts

On December 22, 2017, President Trump signed the Tax Act into law, which, among other provisions, reduces the maximum federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. As a result of the Tax Act, the Subsidiary Registrants revalued their deferred tax assets and deferred tax liabilities, as of December 31, 2017, to account for the future impact of lower corporate tax rates on these deferred tax amounts. For the Subsidiary Registrants regulated operations, where the reduction is expected to be accounted for and applied to customers' rates in future commission proceedings, including rate proceedings, the net remeasurement has been deferred as a regulatory liability. Each of the Subsidiary Registrant's regulatory commissions is reviewing the Tax Act to determine the potential impacts on customer rates. Beginning in January 2018, the Subsidiary Registrants will defer the estimated ongoing impacts of the Tax Act that are expected to be returned to customers. See Note 22 for additional information.

Duke Energy Carolinas and Duke Energy Progress

Ash Basin Closure Costs Deferral

On December 30, 2016, Duke Energy Carolinas and Duke Energy Progress filed a joint petition with the NCUC seeking an accounting order authorizing deferral of certain costs incurred in connection with federal and state environmental remediation requirements related to the permanent closure of ash basins and other ash storage units at coal-fired generating facilities that have provided or are providing generation to customers located in North Carolina. Initial comments were received in March 2017, and reply comments were filed on April 19, 2017. The NCUC has consolidated Duke Energy Carolinas' and Duke Energy Progress' coal ash deferral requests into their respective general rate case dockets for decision. See "2017 North Carolina Rate Case" sections below for additional discussion. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Carolinas

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Carolinas' Consolidated Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[(a)]				
AROs - coal ash	**$ 1,645**	$ 1,536	(i)	(b)
AROs - nuclear and other	**—**	9		
Accrued pension and OPEB	**410**	481		(j)
Retired generation facilities[(c)]	**29**	39	X	2023
Net regulatory asset related to income taxes[(d)]	**—**	484		
Hedge costs deferrals[(c)]	**109**	93	X	2041
DSM/EE	**210**	122	(h)	(h)
Vacation accrual	**83**	76	(e)	2018
Deferred fuel and purchased power	**140**	—	(f)	2018
Nuclear deferral	**84**	92		2019
PISCC[(c)]	**35**	70	X	(b)
AMI	**185**	172	X	(b)
Other	**222**	223		(b)
Total regulatory assets	**3,152**	3,397		
Less: current portion	**299**	238		
Total noncurrent regulatory assets	**$ 2,853**	$ 3,159		
Regulatory Liabilities[(a)]				
Costs of removal[(c)]	**$ 2,054**	$ 2,015	X	(g)
ARO - nuclear and other	**806**	461		(b)
Net regulatory liability related to income taxes[(d)]	**3,028**	—		(b)
Storm reserve[(c)]	**20**	22		(b)
Accrued pension and OPEB	**44**	46		(j)
Deferred fuel and purchased power	**46**	105	(f)	2018
Other	**359**	352		(b)
Total regulatory liabilities	**6,357**	3,001		
Less: current portion	**126**	161		
Total noncurrent regulatory liabilities	**$ 6,231**	$ 2,840		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.

(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Includes regulatory liabilities related to the change in the North Carolina tax rate discussed in Note 22.
(e) Earns a return on outstanding balance in North Carolina.
(f) Pays interest on over-recovered costs in North Carolina. Includes certain purchased power costs in North Carolina and South Carolina and costs of distributed energy in South Carolina.
(g) Recovered over the life of the associated assets.
(h) Includes incentives on DSM/EE investments and is recovered through an annual rider mechanism.
(i) Earns a debt return on coal ash expenditures for North Carolina and South Carolina retail customers.
(j) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

2017 North Carolina Rate Case

On August 25, 2017, Duke Energy Carolinas filed an application with the NCUC for a rate increase for retail customers of approximately $647 million, which represents an approximate 13.6 percent increase in annual base revenues. The rate increase is driven by capital investments subsequent to the previous base rate case, including grid improvement projects, AMI, investments in customer service technologies, costs of complying with coal combustion residuals (CCR) regulations and the North Carolina Coal Ash Management Act of 2014 (Coal Ash Act) and recovery of costs related to licensing and development of the William States Lee III Nuclear Station (Lee Nuclear Station) discussed below. On January 23, 2018, the North Carolina Public Staff filed testimony recommending an overall rate decrease of approximately $290 million. An evidentiary hearing is scheduled to begin on February 27, 2018, and a decision and revised customer rates are expected by mid-2018. Duke Energy Carolinas cannot predict the outcome of this matter.

FERC Formula Rate Matter

On July 31, 2017, Piedmont Municipal Power Agency (PMPA) filed a complaint with FERC against Duke Energy Carolinas alleging that Duke Energy Carolinas misapplied the formula rate under the purchase power agreement (PPA) between the parties by including regulatory amortization in its rates without FERC approval. Duke Energy Carolinas disagreed with PMPA as it believed it was properly applying its FERC filed rate. On February 15, 2018, FERC issued an order ruling in favor of PMPA and ordered Duke Energy Carolinas to refund to PMPA all amounts improperly collected under the PPA. Resolution of this matter is not expected to be material.

Lincoln County Combustion Turbine

On December 7, 2017, the NCUC issued an order approving a Certificate of Public Convenience and Necessity (CPCN) for Duke Energy Carolinas' proposed 402-megawatt (MW) simple cycle, advanced combustion turbine natural gas-fueled electric generating unit at its existing Lincoln County site. The CPCN also includes construction of related transmission and natural gas pipeline interconnection facilities. Construction is scheduled to begin in 2018 with an extended commissioning and validation period from 2020-2024 and an estimated commercial operation date in 2024. As a condition of the approval, Duke Energy Carolinas will not seek recovery of costs associated with the project until it is placed into commercial operation.

Advanced Metering Infrastructure Deferral

On July 12, 2016, the PSCSC issued an accounting order for Duke Energy Carolinas to defer the financial effects of depreciation expense incurred for the installation of AMI meters, the carrying costs on the investment at its weighted average cost of capital (WACC) and the carrying costs on the deferred costs at its WACC not to exceed $45 million. The decision also allows Duke Energy Carolinas to continue to depreciate the non-AMI meters to be replaced. Current retail rates will not change as a result of the decision and the ability of interested parties to challenge the reasonableness of expenditures in subsequent proceedings is not limited.

William States Lee Combined Cycle Facility

On April 9, 2014, the PSCSC granted Duke Energy Carolinas and North Carolina Electric Membership Corporation (NCEMC) a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) for the construction and operation of a 750-MW combined-cycle natural gas-fired generating plant at Duke Energy Carolinas' existing William States Lee Generating Station in Anderson, South Carolina. Duke Energy Carolinas began construction in July 2015 and estimates a cost to build of $600 million for its share of the facility, including allowance for funds used during construction (AFUDC). The project is expected to be commercially available in the first quarter of 2018. NCEMC will own approximately 13 percent of the project. On July 3, 2014, the South Carolina Coastal Conservation League (SCCL) and Southern Alliance for Clean Energy (SACE) jointly filed a Notice of Appeal with the Court of Appeals of South Carolina (S.C. Court of Appeals) seeking the court's review of the PSCSC's decision, claiming the PSCSC did not properly consider a request related to a proposed solar facility prior to granting approval of the CECPCN. The S.C. Court of Appeals affirmed the PSCSC's decision on February 10, 2016, and on March 24, 2016, denied a request for rehearing filed by SCCL and SACE. On April 21, 2016, SCCL and SACE petitioned the South Carolina Supreme Court for review of the S.C. Court of Appeals decision. On March 24, 2017, the South Carolina Supreme Court denied the request for review, thus concluding the matter.

Lee Nuclear Station

In December 2007, Duke Energy Carolinas applied to the NRC for combined operating licenses (COLs) for two Westinghouse AP1000 reactors for the proposed William States Lee III Nuclear Station to be located at a site in Cherokee County, South Carolina. The NCUC and PSCSC concurred with the prudency of Duke Energy Carolinas incurring certain project development and preconstruction costs through several separately issued orders, although full cost recovery is not guaranteed. In December 2016, the NRC issued a COL for each reactor. Duke Energy Carolinas is not required to build the nuclear reactors as result of the COLs being issued.

On March 29, 2017, Westinghouse filed for voluntary Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the Southern District of New York. As part of its 2017 North Carolina Rate Case discussed above, Duke Energy Carolinas is seeking NCUC approval to cancel the development of the Lee Nuclear Station project due to the Westinghouse bankruptcy filing and other market activity and is requesting recovery of incurred licensing and development costs. Duke Energy Carolinas will maintain the license issued by the NRC in December 2016 as an option for potential future development. As of December 31, 2017, Duke Energy Carolinas has incurred approximately $558 million of costs, including AFUDC, related to the project. These project costs are included in Net property, plant and equipment on Duke Energy Carolinas’ Consolidated Balance Sheets. Duke Energy Carolinas cannot predict the outcome of this matter.

Duke Energy Progress

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Progress' Consolidated Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	2017	2016	a Return	Period Ends
Regulatory Assets[(a)]				
AROs - coal ash	**$ 1,975**	$ 1,822	(i)	(b)
AROs - nuclear and other	**359**	275		(c)
Accrued pension and OPEB	**430**	423		(l)
Retired generation facilities	**170**	165	X	2023
Net regulatory asset related to income taxes	**—**	7		(d)
Storm cost deferrals[(e)]	**150**	148	X	(b)
Hedge costs deferrals	**64**	66		(b)
DSM/EE[(f)]	**264**	263	(j)	2018
Vacation accrual	**42**	38		2018
Deferred fuel and purchased power	**130**	24	(g)	2018
Nuclear deferral	**35**	38		2019
PISCC and deferred operating expenses	**38**	42	X	2054
AMI	**75**	—		(b)
NCEMPA deferrals	**53**	51	(h)	2042
Other	**74**	69		(b)
Total regulatory assets	**3,859**	3,431		
Less: current portion	**352**	188		
Total noncurrent regulatory assets	**$ 3,507**	$ 3,243		
Regulatory Liabilities[(a)]				
Costs of removal	**$ 2,122**	$ 1,840	X	(k)
Net regulatory liability related to income taxes	**1,854**	—		(b)
Deferred fuel and purchased power	**1**	64	(g)	2018
Other	**161**	200		(b)
Total regulatory liabilities	**4,138**	2,104		
Less: current portion	**139**	158		
Total noncurrent regulatory liabilities	**$ 3,999**	$ 1,946		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Recovery period for costs related to nuclear facilities runs through the decommissioning period of each unit.
(d) Recovery over the life of the associated assets. Includes regulatory liabilities related to the change in the North Carolina tax rate discussed in Note 22.
(e) South Carolina storm costs are included in rate base.
(f) Included in rate base.
(g) Pays interest on over-recovered costs in North Carolina. Includes certain purchased power costs in North Carolina and South Carolina and costs of distributed energy in South Carolina.
(h) South Carolina retail allocated costs are earning a return.
(i) Earns a debt return on coal ash expenditures for North Carolina and South Carolina retail customers.
(j) Includes incentives on DSM/EE investments.
(k) Recovered over the life of the associated assets.
(l) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

2017 North Carolina Rate Case

On June 1, 2017, Duke Energy Progress filed an application with the NCUC for a rate increase for retail customers of approximately $477 million, which represented an approximate 14.9 percent increase in annual base revenues. Subsequent to the filing, Duke Energy Progress adjusted the requested amount to $420 million, representing an approximate 13 percent increase. The rate increase is driven by capital investments subsequent to the previous base rate case, costs of complying with CCR regulations and the Coal Ash Act, costs relating to storm recovery, investments in customer service technologies and recovery of costs associated with renewable purchased power. On November 22, 2017, Duke Energy Progress and the North Carolina Public Staff filed an Agreement and Stipulation of Partial Settlement resolving certain portions of the proceeding, pending NCUC approval. Terms of the settlement include a return on equity of 9.9 percent and a capital structure of 52 percent equity and 48 percent debt. As a result of the settlement, in 2017 Duke Energy Progress recorded pretax charges totaling approximately $25 million to Impairment charges and Operation, maintenance and other on the Consolidated Income Statements, principally related to disallowances from rate base of certain projects at the Mayo and Sutton plants. The settlement does not include agreement on portions of the rate case relating to recovery of deferred storm recovery costs and coal ash basin deferred costs, which will be decided by the NCUC separately. Taking into consideration the settled portions and Duke Energy Progress' requested recovery of the non-settled portions, the requested rate increase is reduced to approximately $300 million. An evidentiary hearing ended December 7, 2017, and a decision and revised customer rates are expected in the first quarter of 2018. Duke Energy Progress cannot predict the outcome of this matter.

Storm Cost Deferral Filings

On December 16, 2016, Duke Energy Progress filed a petition with the NCUC requesting an accounting order to defer certain costs incurred in connection with response to Hurricane Matthew and other significant storms in 2016. The final estimate of incremental operation and maintenance and capital costs of $116 million was filed with the NCUC in September 2017. On March 15, 2017, the NCUC Public Staff filed comments supporting deferral of a portion of Duke Energy Progress' requested amount. Duke Energy Progress filed reply comments on April 12, 2017. On July 10, 2017, the NCUC consolidated Duke Energy Progress' storm deferral request into the Duke Energy Progress rate case docket for decision. See "2017 North Carolina Rate Case" for additional discussion. As of December 31, 2017, Duke Energy Progress has approximately $77 million included in Regulatory assets on its Consolidated Balance Sheets. Duke Energy Progress cannot predict the outcome of this matter.

On December 16, 2016, Duke Energy Progress filed a petition with the PSCSC requesting an accounting order to defer certain costs incurred related to repairs and restoration of service following Hurricane Matthew. The final estimate of incremental operation and maintenance and capital costs was approximately $74 million. In January 2017, the PSCSC approved the deferral request and issued an accounting order. As of December 31, 2017, Duke Energy Progress has approximately $73 million included in Regulatory assets on its Consolidated Balance Sheets.

South Carolina Rate Case

In December 2016, the PSCSC approved a rate case settlement agreement among the ORS (Office of Regulatory Staff), intervenors and Duke Energy Progress. Terms of the settlement agreement included an approximate $56 million increase in revenues over a two-year period. An increase of approximately $38 million in revenues was effective January 1, 2017, and an additional increase of approximately $18.5 million in revenues was effective January 1, 2018. Duke Energy Progress amortized approximately $18.5 million from the cost of removal reserve in 2017. Other settlement terms included a rate of return on equity of 10.1 percent, recovery of coal ash costs incurred from January 1, 2015, through June 30, 2016, over a 15-year period and ongoing deferral of allocated ash basin closure costs from July 1, 2016, until the next base rate case. The settlement also provides that Duke Energy Progress will not seek an increase in rates in South Carolina to occur prior to 2019, with limited exceptions.

Western Carolinas Modernization Plan

On November 4, 2015, Duke Energy Progress announced a Western Carolinas Modernization Plan, which included retirement of the existing Asheville coal-fired plant, the construction of two 280-MW combined-cycle natural gas plants having dual fuel capability, with the option to build a third natural gas simple cycle unit in 2023 based upon the outcome of initiatives to reduce the region's power demand. The plan also included upgrades to existing transmission lines and substations, installation of solar generation and a pilot battery storage project. These investments will be made within the next seven years. Duke Energy Progress is also working with the local natural gas distribution company to upgrade an existing natural gas pipeline to serve the natural gas plant.

On March 28, 2016, the NCUC issued an order approving a CPCN for the new combined-cycle natural gas plants, but denying the CPCN for the contingent simple cycle unit without prejudice to Duke Energy Progress to refile for approval in the future. On March 28, 2017, Duke Energy Progress filed an annual progress report for the construction of the combined-cycle plants with the NCUC, with an estimated cost of $893 million. Site preparation activities for the combined-cycle plants are underway and construction of these plants began in 2017, with an expected in-service date in late 2019. Duke Energy Progress plans to file for future approvals related to the proposed solar generation and pilot battery storage project.

The carrying value of the 376-MW Asheville coal-fired plant, including associated ash basin closure costs, of $385 million and $492 million are included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2017, and 2016, respectively.

Shearon Harris Nuclear Plant Expansion

In 2006, Duke Energy Progress selected a site at Harris to evaluate for possible future nuclear expansion. On February 19, 2008, Duke Energy Progress filed its COL application with the NRC for two Westinghouse AP1000 reactors at Harris, which the NRC docketed for review. On May 2, 2013, Duke Energy Progress filed a letter with the NRC requesting the NRC to suspend its review activities associated with the COL at the Harris site. The NCUC and PSCSC approved deferral of retail costs. Total deferred costs were approximately $47 million as of December 31, 2017, and are recorded in Regulatory assets on Duke Energy Progress’ Consolidated Balance Sheets. On November 17, 2016, the FERC approved Duke Energy Progress’ rate recovery request filing for the wholesale ratepayers’ share of the abandonment costs, including a debt only return to be recovered through revised formula rates and amortized over a 15-year period beginning May 1, 2014. As part of the settlement agreement for the 2017 North Carolina Rate Case discussed above, Duke Energy Progress will amortize the regulatory asset over an eight-year period. The settlement is subject to NCUC approval. Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Florida

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Florida's Consolidated Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs - coal ash[c]	**$ 9**	$ 8	X	(b)
AROs - nuclear and other[c]	**296**	294	X	(b)
Accrued pension and OPEB[c]	**476**	458	X	(h)
Retired generation facilities[c]	**216**	257	X	(b)
Net regulatory asset related to income taxes[c]	**—**	224	X	(d)
Storm cost deferrals[c]	**376**	—	(f)	2021
Nuclear asset securitized balance, net	**1,142**	1,193		2036
Hedge costs deferrals	**30**	25		2018
DSM/EE[c]	**17**	15	X	2018
Deferred fuel and purchased power[c]	**219**	87	(g)	2019
Nuclear deferral	**—**	96		
AMI[c]	**75**	—	X	2032
Other	**36**	36		(b)
Total regulatory assets	**2,892**	2,693		
Less: current portion	**389**	213		
Total noncurrent regulatory assets	**$ 2,503**	$ 2,480		
Regulatory Liabilities[a]				
Costs of removal[c]	**$ 415**	$ 358	(e)	(b)
Net regulatory liability related to income taxes[c]	**948**	—		(b)
Storm reserve[c]	**—**	60		
Deferred fuel and purchased power[c]	**—**	17	(g)	
Other	**18**	44		(b)
Total regulatory liabilities	**1,381**	479		

Less: current portion		**74**	31
Total noncurrent regulatory liabilities	**$**	**1,307** $	448

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Certain costs earn a return.
(f) Earns a debt return/interest once collections begin.
(g) Earns commercial paper rate.
(h) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

Storm Restoration Cost Recovery

In September 2017, Duke Energy Florida’s service territory suffered significant damage from Hurricane Irma, resulting in approximately 1.3 million customers experiencing outages. In the fourth quarter of 2017, Duke Energy Florida also incurred preparation costs related to Hurricane Nate. On December 28, 2017, Duke Energy Florida filed a petition with the FPSC to recover incremental storm restoration costs for Hurricanes Irma and Nate and to replenish the storm reserve. The estimated recovery amount is approximately $513 million to be recovered over a three-year period beginning in March 2018, subject to true up, which includes reestablishment of a $132 million storm reserve. At December 31, 2017, Duke Energy Florida's Consolidated Balance Sheets included approximately $376 million of recoverable costs under the FPSC's storm rule in Regulatory assets within Other Noncurrent Assets related to storm recovery. On February 6, 2018, the FPSC approved Duke Energy Florida's motion to approve a stipulation that would apply tax savings resulting from the Tax Act toward storm costs in lieu of implementing a storm surcharge.

2017 Second Revised and Restated Settlement Agreement

On November 20, 2017, the FPSC issued an order to approve the 2017 Second Revised and Restated Settlement Agreement (2017 Settlement) filed by Duke Energy Florida. The 2017 Settlement replaces and supplants the 2013 Settlement. The 2017 Settlement extends the base rate case stay-out provision from the 2013 Settlement through the end of 2021 unless actual or projected return on equity falls below 9.5 percent; however, Duke Energy Florida is allowed a multiyear increase to its base rates of $67 million per year in 2019, 2020 and 2021, as well as base rate increases for solar generation. In addition to carrying forward the provisions contained in the 2013 Settlement related to the Crystal River 1 and 2 coal units discussed below and future generation needs in Florida, the 2017 Settlement contains provisions related to future investments in solar and renewable energy technology, future investments in AMI technology as well as recovery of existing meters, impacts of the Tax Act, an electric vehicle charging station pilot program and the termination of the proposed Levy Nuclear Project discussed below. As part of the 2017 Settlement, Duke Energy Florida will not move forward with building the Levy nuclear plant and recorded a pretax impairment charge of approximately $135 million in 2017 to write off all unrecovered Levy Nuclear Project costs, including the COL. As a result of the 2017 Settlement, Duke Energy Florida transferred $75 million to a regulatory asset for the net book value of existing meter technology, which will be recovered over a 15-year period.

The 2017 Settlement includes provisions to recover 2017 under-recovered fuel costs of approximately $196 million over a 24-month period beginning in January 2018. On September 1, 2017, Duke Energy Florida submitted Alternate 2018 Fuel and Capacity clause projection filings consistent with the terms of the 2017 Settlement. The updated capacity filing reflects the removal of all Levy costs. The FPSC approved Duke Energy Florida's 2018 Alternate projection filings on October 25, 2017.

Hines Chiller Uprate Project

On February 2, 2017, Duke Energy Florida filed a petition seeking approval to include in base rates the revenue requirement for a Chiller Uprate Project (Uprate Project) at the Hines Energy Complex. The Uprate Project was placed into service in March 2017 at a cost of approximately $150 million. The annual retail revenue requirement is approximately $19 million. On March 28, 2017, the FPSC issued an order approving the revenue requirement, which was included in base rates for the first billing cycle of April 2017.

Citrus County Combined Cycle Facility

On October 2, 2014, the FPSC granted Duke Energy Florida a Determination of Need for the construction of a 1,640-MW combined-cycle natural gas plant in Citrus County, Florida. On May 5, 2015, the Florida Department of Environmental Protection approved Duke Energy Florida's Site Certification Application. The project has received all required permits and approvals and construction began in October 2015. The facility is expected to be commercially available in 2018 at an estimated cost of $1.5 billion, including AFUDC. The plant will receive natural gas from the Sabal Trail Transmission, LLC (Sabal Trail) pipeline discussed below.

Purchase of Osprey Energy Center

Duke Energy Florida received a Civil Investigative Demand from the Department of Justice (DOJ) related to alleged violation of the waiting period for the Hart-Scott-Rodino Antitrust Improvements Act of 1976 related to the purchase of the Osprey Energy Center, LLC, which was completed in January 2017. The DOJ alleged Duke Energy Florida assumed operational control of the Osprey Plant before the waiting period expiration on February 27, 2015. On January 17, 2017, Duke Energy Florida entered into a stipulation agreement to settle with the DOJ for $600,000 without admission of liability. On January 18, 2017, the DOJ filed a complaint and the stipulation in the U.S. District Court for the District of Columbia, which was approved by the court. A final order dismissing the case was entered in April 2017.

Crystal River Unit 3

In December 2014, the FPSC approved Duke Energy Florida's decision to construct an independent spent fuel storage installation (ISFSI) for the retired Crystal River Unit 3 nuclear plant and approved Duke Energy Florida's request to defer amortization of the ISFSI pending resolution of litigation against the federal government as a result of the Department of Energy's breach of its obligation to accept spent nuclear fuel. The return rate is based on the currently approved AFUDC rate with a return on equity of 7.35 percent, or 70 percent of the currently approved 10.5 percent. The return rate is subject to change if the return on equity changes in the future. In September 2016, the FPSC approved an amendment to the 2013 Settlement authorizing recovery of the ISFSI through the Capacity Cost Recovery Clause. Through December 31, 2017, Duke Energy Florida has deferred approximately $113 million for recovery associated with building the ISFSI. See Note 5 for additional information on spent nuclear fuel litigation.

The regulatory asset associated with the original Crystal River Unit 3 power uprate project will continue to be recovered through the NCRC over an estimated seven-year period that began in 2013 with a remaining uncollected balance of $87 million at December 31, 2017.

Crystal River Unit 3 Regulatory Asset

On September 15, 2015, the FPSC approved Duke Energy Florida's motion for approval of a settlement agreement with intervenors to reduce the value of the projected Crystal River Unit 3 regulatory asset to be recovered to $1.283 billion as of December 31, 2015. An impairment charge of $15 million was recognized in 2015 to adjust the regulatory asset balance. In November 2015, the FPSC issued a financing order approving Duke Energy Florida’s request to issue nuclear asset-recovery bonds to finance its unrecovered regulatory asset related to Crystal River Unit 3 through a wholly owned special purpose entity. Nuclear asset-recovery bonds replace the base rate recovery methodology authorized by the 2013 Settlement and result in a lower rate impact to customers with a recovery period of approximately 20 years.

Pursuant to provisions in Florida Statutes and the FPSC financing order, in 2016, Duke Energy Florida formed Duke Energy Florida Project Finance, LLC (DEFPF), a wholly owned, bankruptcy remote special purpose subsidiary for the purpose of issuing nuclear asset-recovery bonds. In June 2016, DEFPF issued $1,294 million aggregate principal amount of senior secured bonds (nuclear asset-recovery bonds) to finance the recovery of Duke Energy Florida's Crystal River 3 regulatory asset.

In connection with this financing, net proceeds to DEFPF of approximately $1,287 million, after underwriting costs, were used to acquire nuclear asset-recovery property from Duke Energy Florida and to pay transaction related expenses. The nuclear asset-recovery property includes the right to impose, bill, collect and adjust a non-bypassable nuclear asset-recovery charge, to be collected on a per kilowatt-hour basis, from all Duke Energy Florida retail customers until the bonds are paid in full. Duke Energy Florida began collecting the nuclear asset-recovery charge on behalf of DEFPF in customer rates in July 2016.

See Note 17 for additional information.

Levy Nuclear Project

On July 28, 2008, Duke Energy Florida applied to the NRC for COLs for two Westinghouse AP1000 reactors at Levy (Levy Nuclear Project). In 2008, the FPSC granted Duke Energy Florida's petition for an affirmative Determination of Need and related orders requesting cost recovery under Florida's nuclear cost-recovery rule, together with the associated facilities, including transmission lines and substation facilities. In October 2016, the NRC issued COLs for the proposed Levy Nuclear Plant Units 1 and 2. Duke Energy Florida is not required to build the nuclear reactors as a result of the COLs being issued.

On January 28, 2014, Duke Energy Florida terminated the Levy engineering, procurement and construction agreement (EPC). Duke Energy Florida may be required to pay for work performed under the EPC. Duke Energy Florida recorded an exit obligation in 2014 for the termination of the EPC. This liability was recorded within Other in Other Noncurrent Liabilities with an offset primarily to Regulatory assets on the Consolidated Balance Sheets. Duke Energy Florida is allowed to recover reasonable and prudent EPC cancellation costs from its retail customers. On May 1, 2017, Duke Energy Florida filed a request with the FPSC to recover approximately $82 million of Levy Nuclear Project costs from retail customers in 2018. As part of the 2017 Settlement discussed above, Duke Energy Florida is no longer seeking recovery of costs related to the Levy Nuclear Project and the ongoing Westinghouse litigation discussed in Note 5. All remaining Levy Nuclear Project issues have been resolved.

Crystal River 1 and 2 Coal Units

Duke Energy Florida has evaluated Crystal River 1 and 2 coal units for retirement in order to comply with certain environmental regulations. Based on this evaluation, those units are expected to be retired by the end of 2018. Once those units are retired Duke Energy Florida will continue recovery of existing annual depreciation expense through the end of 2020. Beginning in 2021, Duke Energy Florida will be allowed to recover any remaining net book value of the assets from retail customers through the Capacity Cost Recovery Clause.

Duke Energy Ohio

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Ohio's Consolidated Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[(a)]				
AROs - coal ash	**$ 17**	$ 12	X	(b)
Accrued pension and OPEB	**139**	135		(g)
Net regulatory asset related to income taxes[(c)]	**—**	63		(d)
Storm cost deferrals	**5**	5		(b)
Hedge costs deferrals	**6**	7		(b)
DSM/EE	**18**	6	(f)	(e)
Grid modernization	**39**	65	X	(e)
Vacation accrual	**5**	4		2018
Deferred fuel and purchased power	**—**	5		
PISCC and deferred operating expenses[(c)]	**19**	20	X	2083
Transmission expansion obligation	**50**	71		(e)
MGP	**91**	99		(b)
AMI	**6**	—		(b)
East Bend deferrals	**45**	32	X	(b)
Deferred pipeline integrity costs	**12**	7	X	(b)
Other	**42**	26		(b)
Total regulatory assets	**494**	557		

Less: current portion		**49**	37	
Total noncurrent regulatory assets	**$**	**445** $	520	
Regulatory Liabilities[(a)]				
Costs of removal	**$**	**189** $	212	(d)
Net regulatory liability related to income taxes		**688**	—	(b)
Accrued pension and OPEB		**16**	19	(g)
Deferred fuel and purchased power		**—**	6	
Other		**34**	20	(b)
Total regulatory liabilities		**927**	257	
Less: current portion		**36**	21	
Total noncurrent regulatory liabilities	**$**	**891** $	236	

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Recovered via a rider mechanism.
(f) Includes incentives on DSM/EE investments.
(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

Duke Energy Kentucky Rate Case

On September 1, 2017, Duke Energy Kentucky filed a rate case with the KPSC requesting an increase in electric base rates of approximately $49 million, which represents an approximate 15 percent increase on the average customer bill. The rate increase is driven by increased investment in utility plant, increased operations and maintenance expenses and recovery of regulatory assets. The application also includes implementation of the Environmental Surcharge Mechanism to recover environmental costs not included in base rates, requests to establish a Distribution Capital Investment Rider to recover incremental costs of specific programs, requests to establish a FERC Transmission Cost Reconciliation Rider to recover escalating transmission costs and modification to the Profit Sharing Mechanism to increase customers' share of proceeds from the benefits of owning generation and to mitigate shareholder risks associated with that generation. An evidentiary hearing is scheduled to begin on March 6, 2018. Duke Energy Kentucky anticipates that rates will go into effect in mid-April 2018. Duke Energy Kentucky cannot predict the outcome of this matter.

2017 Electric Security Plan

On June 1, 2017, Duke Energy Ohio filed with the PUCO a request for a standard service offer in the form of an electric security plan (ESP). If approved by the PUCO, the term of the ESP would be from June 1, 2018, to May 31, 2024. Terms of the ESP include continuation of market-based customer rates through competitive procurement processes for generation, continuation and expansion of existing rider mechanisms and proposed new rider mechanisms relating to regulatory mandates, costs incurred to enhance the customer experience and transform the grid and a service reliability rider for vegetation management. On February 15, 2018, the procedural schedule was suspended to facilitate ongoing settlement discussions. Duke Energy Ohio cannot predict the outcome of this matter.

Woodsdale Station Fuel System Filing

On June 9, 2015, the FERC ruled in favor of PJM Interconnection, LLC (PJM) on a revised Tariff and Reliability Assurance Agreement including implementation of a Capacity Performance (CP) proposal and to amend sections of the Operating Agreement related to generation non-performance. The CP proposal includes performance-based penalties for non-compliance. Duke Energy Kentucky is a Fixed Resource Requirement (FRR) entity, and therefore is subject to the compliance standards through its FRR plans. A partial CP obligation will apply to Duke Energy Kentucky in the delivery year beginning June 1, 2019, with full compliance beginning June 1, 2020. Duke Energy Kentucky has developed strategies for CP compliance investments. On December 21, 2017, the KPSC issued an order approving Duke Energy Kentucky's request for a CPCN to construct an ultra-low sulfur diesel backup fuel system for the Woodsdale Station. The backup fuel system is projected to cost approximately $55 million and is anticipated to be in service prior to the CP compliance deadline of April 2019.

Ohio Valley Electric Corporation

On March 31, 2017, Duke Energy Ohio filed for approval to adjust its existing price stabilization rider (Rider PSR), which is currently set at zero dollars, to pass through net costs related to its contractual entitlement to capacity and energy from the generating assets owned by OVEC. The filing seeks to adjust Rider PSR for OVEC costs subsequent to April 1, 2017. Duke Energy Ohio is seeking deferral authority for net costs incurred from April 1, 2017, until the new rates under Rider PSR are put into effect. Various intervenors have filed motions to dismiss or stay the proceeding and Duke Energy Ohio has opposed these filings. See Note 13 for additional discussion of Duke Energy Ohio's ownership interest in OVEC. Duke Energy Ohio cannot predict the outcome of this matter.

East Bend Coal Ash Basin Filing

On December 2, 2016, Duke Energy Kentucky filed with the KPSC a request for a CPCN for construction projects necessary to close and repurpose an ash basin at the East Bend facility as a result of current and proposed EPA regulations. Duke Energy Kentucky estimated a total cost of approximately $93 million in the filing and expects in-service date by the first quarter of 2021. On June 6, 2017, the KPSC approved the CPCN request.

Electric Base Rate Case

Duke Energy Ohio filed with the PUCO an electric distribution base rate case application and supporting testimony in March 2017. Duke Energy Ohio requested an estimated annual increase of approximately $15 million and a return on equity of 10.4 percent. The application also includes requests to continue certain current riders and establish new riders. On September 26, 2017, the PUCO staff filed a report recommending a revenue decrease between approximately $18 million and $29 million and a return on equity between 9.22 percent and 10.24 percent. On February 15, 2018, the procedural schedule was suspended to facilitate ongoing settlement discussions. Duke Energy Ohio expects rates will go into effect the second quarter of 2018. Duke Energy Ohio cannot predict the outcome of this matter.

Natural Gas Pipeline Extension

Duke Energy Ohio is proposing to install a new natural gas pipeline in its Ohio service territory to increase system reliability and enable the retirement of older infrastructure. On January 20, 2017, Duke Energy Ohio filed an amended application with the Ohio Power Siting Board for approval of one of two proposed routes. A public hearing was held on June 15, 2017, and an adjudicatory hearing was scheduled to begin September 11, 2017. On August 24, 2017, an administrative law judge (ALJ) granted a request made by Duke Energy Ohio to delay the procedural schedule while it works through various issues related to the pipeline route. If approved, construction of the pipeline extension is expected to be completed before the 2020/2021 winter season. The proposed project involves the installation of a natural gas line and is estimated to cost approximately $110 million, excluding AFUDC.

Advanced Metering Infrastructure

On April 25, 2016, Duke Energy Kentucky filed with the KPSC an application for approval of a CPCN for the construction of advanced metering infrastructure. Duke Energy Kentucky estimates the $49 million project will take two years to complete. Duke Energy Kentucky also requested approval to establish a regulatory asset for the remaining book value of existing meter equipment and inventory to be replaced. Duke Energy Kentucky and the Kentucky attorney general entered into a stipulation to settle matters related to the application. On May 25, 2017, the KPSC issued an order to approve the stipulation with certain modifications. On June 1, 2017, Duke Energy Kentucky filed its acceptance of the modifications. The deployment of AMI meters began in third quarter 2017 and is expected to be completed in early 2019. Duke Energy Ohio has approximately $6 million included in Regulatory assets on its Consolidated Balance Sheets at December 31, 2017, for the book value of existing meter equipment.

Accelerated Natural Gas Service Line Replacement Rider

On January 20, 2015, Duke Energy Ohio filed an application for approval of an accelerated natural gas service line replacement program (ASRP). Under the ASRP, Duke Energy Ohio proposed to replace certain natural gas service lines on an accelerated basis over a 10-year period. Duke Energy Ohio also proposed to complete preliminary survey and investigation work related to natural gas service lines that are customer owned and for which it does not have valid records and, further, to relocate interior natural gas meters to suitable exterior locations where such relocation can be accomplished. Duke Energy Ohio's projected total capital and operations and maintenance expenditures under the ASRP were approximately $240 million. The filing also sought approval of a rider mechanism (Rider ASRP) to recover related expenditures. Duke Energy Ohio proposed to update Rider ASRP on an annual basis. Intervenors opposed the ASRP, primarily because they believe the program is neither required nor necessary under federal pipeline regulation. On October 26, 2016, the PUCO issued an order denying the proposed ASRP. Duke Energy Ohio's application for rehearing of the PUCO decision was denied on May 17, 2017.

Energy Efficiency Cost Recovery

On March 28, 2014, Duke Energy Ohio filed an application for recovery of program costs, lost distribution revenue and performance incentives related to its energy efficiency and peak demand reduction programs. These programs are undertaken to comply with environmental mandates set forth in Ohio law. The PUCO approved Duke Energy Ohio's application but found that Duke Energy Ohio was not permitted to use banked energy savings from previous years in order to calculate the amount of allowed incentive. This conclusion represented a change to the cost recovery mechanism that had been agreed upon by intervenors and approved by the PUCO in previous cases. The PUCO granted the applications for rehearing filed by Duke Energy Ohio and an intervenor. On January 6, 2016, Duke Energy Ohio and the PUCO Staff entered into a stipulation, pending the PUCO's approval, to resolve issues related to performance incentives and the PUCO Staff audit of 2013 costs, among other issues. In December 2015, based upon the stipulation, Duke Energy Ohio re-established approximately $20 million of the revenues that had been previously reversed. On October 26, 2016, the PUCO issued an order approving the stipulation without modification. In December 2016, the PUCO granted the intervenors request for rehearing for the purpose of further review. Duke Energy Ohio cannot predict the outcome of this matter.

On June 15, 2016, Duke Energy Ohio filed an application for approval of a three-year energy efficiency and peak demand reduction portfolio of programs. A stipulation and modified stipulation were filed on December 22, 2016, and January 27, 2017, respectively. Under the terms of the stipulations, which included support for deferral authority of all costs and a cap on shared savings incentives, Duke Energy Ohio offered its energy efficiency and peak demand reduction programs throughout 2017. On February 3, 2017, Duke Energy Ohio filed for deferral authority of its costs incurred in 2017 in respect of its proposed energy efficiency and peak demand reduction portfolio. On September 27, 2017, the PUCO issued an order approving a modified stipulation. The modifications impose an annual cap of approximately $38 million on program costs and shared savings incentives combined, but allowed for Duke Energy Ohio to file for a waiver of costs in excess of the cap in 2017. The PUCO approved the waiver request up to a total cost of $56 million. On November 21, 2017, the PUCO granted Duke Energy Ohio's and intervenor's applications for rehearing of the September 27, 2017, order. On January 10, 2018, the PUCO denied the Ohio Consumers' Counsel's application for rehearing of the PUCO order granting Duke Energy Ohio's waiver request. Duke Energy Ohio cannot predict the outcome of this matter.

2014 Electric Security Plan

In April 2015, the PUCO modified and approved Duke Energy Ohio's proposed electric security plan (ESP), with a three-year term and an effective date of June 1, 2015. The PUCO approved a competitive procurement process for SSO load, a distribution capital investment rider and a tracking mechanism for incremental distribution expenses caused by major storms. The PUCO also approved a placeholder tariff for a price stabilization rider, but denied Duke Energy Ohio's specific request to include Duke Energy Ohio's entitlement to generation from OVEC in the rider at this time; however, the order allows Duke Energy Ohio to submit additional information to request recovery in the future. On May 4, 2015, Duke Energy Ohio filed an application for rehearing requesting the PUCO to modify or amend certain aspects of the order. On May 28, 2015, the PUCO granted all applications for rehearing filed in the case for future consideration. Duke Energy Ohio cannot predict the outcome of the appeals in this matter.

2012 Natural Gas Rate Case/MGP Cost Recovery

On November 13, 2013, the PUCO issued an order approving a settlement of Duke Energy Ohio's natural gas base rate case and authorizing the recovery of costs incurred between 2008 and 2012 for environmental investigation and remediation of two former MGP sites. The PUCO order also authorized Duke Energy Ohio to continue deferring MGP environmental investigation and remediation costs incurred subsequent to 2012 and to submit annual filings to adjust the MGP rider for future costs. Intervening parties appealed this decision to the Ohio Supreme Court and on June 29, 2017, the Ohio Supreme Court issued its decision affirming the PUCO order. Appellants filed a request for reconsideration, which was denied on September 27, 2017. This matter is now final.

The PUCO order also contained deadlines for completing the MGP environmental investigation and remediation costs at the MGP sites. For the property known as the East End site, the PUCO order established a deadline of December 31, 2016, which was subsequently extended to December 31, 2019. In January 2017, intervening parties filed for rehearing of the PUCO's decision. On February 8, 2017, the PUCO denied the rehearing request. As of December 31, 2017, Duke Energy Ohio had approximately, $35 million included in Regulatory assets on the Consolidated Balance Sheets for future remediation costs expected to be incurred at the East End site.

Regional Transmission Organization Realignment

Duke Energy Ohio, including Duke Energy Kentucky, transferred control of its transmission assets from MISO to PJM Interconnection, LLC (PJM), effective December 31, 2011. The PUCO approved a settlement related to Duke Energy Ohio's recovery of certain costs of the Regional Transmission Organization (RTO) realignment via a non-bypassable rider. Duke Energy Ohio is allowed to recover all MISO Transmission Expansion Planning (MTEP) costs, including but not limited to Multi Value Project (MVP) costs, directly or indirectly charged to Ohio customers. Duke Energy Ohio also agreed to vigorously defend against any charges for MVP projects from MISO. The KPSC also approved a request to effect the RTO realignment, subject to a commitment not to seek double recovery in a future rate case of the transmission expansion fees that may be charged by MISO and PJM in the same period or overlapping periods.

The following table provides a reconciliation of the beginning and ending balance of Duke Energy Ohio's recorded liability for its exit obligation and share of MTEP costs, excluding MVP, recorded within Other in Current liabilities and Other in Other Noncurrent Liabilities on the Consolidated Balance Sheets. The retail portions of MTEP costs billed by MISO are recovered by Duke Energy Ohio through a non-bypassable rider. As of December 31, 2017, and 2016, $50 million and $71 million are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets, respectively.

(in millions)	December 31, 2016	Provisions/ Adjustments	Cash Reductions	December 31, 2017
Duke Energy Ohio	$ 90	$ (20)	$ (4)	$ 66

MVP. MISO approved 17 MVP proposals prior to Duke Energy Ohio's exit from MISO on December 31, 2011. Construction of these projects is expected to continue through 2020. Costs of these projects, including operating and maintenance costs, property and income taxes, depreciation and an allowed return, are allocated and billed to MISO transmission owners.

On December 29, 2011, MISO filed a tariff with the FERC providing for the allocation of MVP costs to a withdrawing owner based on monthly energy usage. The FERC set for hearing (i) whether MISO's proposed cost allocation methodology to transmission owners who withdrew from MISO prior to January 1, 2012, is consistent with the tariff at the time of their withdrawal from MISO and, (ii) if not, what the amount of and methodology for calculating any MVP cost responsibility should be. In 2012, MISO estimated Duke Energy Ohio's MVP obligation over the period from 2012 to 2071 at $2.7 billion, on an undiscounted basis. On July 16, 2013, a FERC Administrative Law Judge (ALJ) issued an initial decision. Under this initial decision, Duke Energy Ohio would be liable for MVP costs. Duke Energy Ohio filed exceptions to the initial decision, requesting FERC to overturn the ALJ's decision.

On October 29, 2015, the FERC issued an order reversing the ALJ's decision. The FERC ruled the cost allocation methodology is not consistent with the MISO tariff and that Duke Energy Ohio has no liability for MVP costs after its withdrawal from MISO. On May 19, 2016, the FERC denied the request for rehearing filed by MISO and the MISO Transmission Owners. On July 15, 2016, the MISO Transmission Owners filed a petition for review with the U.S. Court of Appeals for the Sixth Circuit. On June 21, 2017, a three-judge panel affirmed FERC's 2015 decision holding that Duke Energy Ohio has no liability for the cost of the MVP projects constructed after Duke Energy Ohio's withdrawal from MISO. MISO did not file further petitions for review and this matter is now final.

Duke Energy Indiana

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Indiana's Consolidated Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs - coal ash	**$ 380**	$ 276		(b)
Accrued pension and OPEB	**197**	222		(g)
Retired generation facilities[c]	**65**	73	X	2025
Net regulatory asset related to income taxes	**—**	119		(d)
Hedge costs deferrals	**25**	26		(b)
DSM/EE	**21**	—	(e)	(e)
Vacation accrual	**11**	10		2018
Deferred fuel and purchased power	**18**	40		2018
PISCC and deferred operating expenses[c]	**274**	281	X	(b)
Gasification services agreement buyout[f]	**—**	8		
AMI[c]	**21**	46	X	(b)
Other	**131**	121		(b)
Total regulatory assets	**1,143**	1,222		
Less: current portion	**165**	149		
Total noncurrent regulatory assets	**$ 978**	$ 1,073		
Regulatory Liabilities[a]				
Costs of removal	**$ 644**	$ 660		(d)
Net regulatory liability related to income taxes	**998**	—		(b)
Amounts to be refunded to customers	**10**	45		2018
Accrued pension and OPEB	**64**	72		(g)
Other	**31**	11		(b)
Total regulatory liabilities	**1,747**	788		

Less: current portion		**24**	40
Total noncurrent regulatory liabilities	**$**	**1,723** $	748

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Includes incentives on DSM/EE investments and is recovered through a tracker mechanism over a two-year period.
(f) The IURC authorized Duke Energy Indiana to recover costs incurred to buy out a gasification services agreement, including carrying costs through 2017.
(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

Coal Combustion Residual Plan

On March 17, 2016, Duke Energy Indiana filed with the IURC a request for approval of its first group of federally mandated CCR rule compliance projects (Phase I CCR Compliance Projects) to comply with the EPA's CCR rule. The projects in this Phase I filing are CCR compliance projects, including the conversion of Cayuga and Gibson stations to dry bottom ash handling and related water treatment. Duke Energy Indiana requested timely recovery of approximately $380 million in retail capital costs, including AFUDC, and recovery of incremental operating and maintenance costs under a federal mandate tracker that provides for timely recovery of 80 percent of such costs and deferral with carrying costs of 20 percent of such costs for recovery in a subsequent retail base rate case. On January 24, 2017, Duke Energy Indiana and various intervenors filed a settlement agreement with the IURC. Terms of the settlement include recovery of 60 percent of the estimated CCR compliance construction project capital costs through existing rider mechanisms and deferral of 40 percent of these costs until Duke Energy Indiana's next general retail rate case. The deferred costs will earn a return based on Duke Energy Indiana's long-term debt rate of 4.73 percent until costs are included in retail rates, at which time the deferred costs will earn a full return. Costs are to be capped at $365 million, plus actual AFUDC. Costs above the cap would be considered for recovery in the next rate case. Terms of the settlement agreement also require Duke Energy Indiana to perform certain reporting and groundwater monitoring. On May 24, 2017, the IURC approved the settlement agreement.

Edwardsport Integrated Gasification Combined Cycle Plant

Costs for the Edwardsport Integrated Gasification Combined Cycle (IGCC) Plant are recovered from retail electric customers via a tracking mechanism (IGCC rider) with updates filed by Duke Energy Indiana. The IGCC Plant was placed into commercial operation in June 2013.

On August 24, 2016, the IURC approved a settlement (IGCC Settlement) among Duke Energy Indiana and several intervenors to resolve disputes related to five IGCC riders (the 11th through 15th) and a subdocket to Duke Energy Indiana's fuel adjustment clause. The IGCC settlement resulted in customers not being billed for previously incurred plant operating costs of $87.5 million and payments and commitments from Duke Energy Indiana of $5.5 million for attorneys’ fees and consumer programs funding. Duke Energy Indiana recognized pretax impairment and related charges of $93 million in 2015. Additionally, under the IGCC settlement, the recovery of operating and maintenance expenses and ongoing maintenance capital at the plant were subject to certain caps during the years of 2016 and 2017. The IGCC settlement also included a commitment to either retire or stop burning coal by December 31, 2022, at the Gallagher Station. Pursuant to the IGCC settlement, the in-service date used for accounting and ratemaking will remain as June 2013. Remaining deferred costs will be recovered over eight years beginning in 2016 and not earn a carrying cost. As of December 31, 2017, deferred costs related to the project are approximately $152 million and are included in Regulatory assets in Current Assets and Other Noncurrent Assets on Duke Energy Indiana's Consolidated Balance Sheets. Under the IGCC settlement, future IGCC riders will be filed annually with the next filing scheduled for first quarter 2018.

The ninth semi-annual IGCC rider order was appealed by various intervenors and the matter was remanded to the IURC for further proceedings and additional findings on a tax in-service issue. On February 2, 2017, the IURC issued an order upholding the original decision, finding that an estimate of impact on customer rates due to the federal income tax in-service determination was reasonable.

FERC Transmission Return on Equity Complaint

Customer groups have filed with the FERC complaints against MISO and its transmission-owning members, including Duke Energy Indiana, alleging, among other things, that the current base rate of return on equity earned by MISO transmission owners of 12.38 percent is unjust and unreasonable. The complaints claim, among other things, that the current base rate of return on equity earned by MISO transmission owners should be reduced to 8.67 percent. On January 5, 2015, the FERC issued an order accepting the MISO transmission owners' adder of 0.50 percent to the base rate of return on equity based on participation in an RTO subject to it being applied to a return on equity that is shown to be just and reasonable in the pending return on equity complaints. On December 22, 2015, the presiding FERC ALJ in the first complaint issued an Initial Decision in which the base rate of return on equity was set at 10.32 percent. On September 28, 2016, the Initial Decision in the first complaint was affirmed by FERC, but is subject to rehearing requests. On June 30, 2016, the presiding FERC ALJ in the second complaint issued an Initial Decision setting the base rate of return on equity at 9.70 percent. The Initial Decision in the second complaint is pending FERC review. On April 14, 2017, the U.S. Court of Appeals for the District of Columbia Circuit, in *Emera Maine v. FERC*, reversed and remanded certain aspects of the methodology employed by FERC to establish rates of return on equity. This decision may affect the outcome of the complaints against Duke Energy Indiana. Duke Energy Indiana currently believes these matters will not have a material impact on its results of operations, cash flows and financial position.

Grid Infrastructure Improvement Plan

On December 7, 2015, Duke Energy Indiana filed a grid infrastructure improvement plan with an estimated cost of $1.8 billion in response to guidance from IURC orders and the Indiana Court of Appeals decisions related to a new statute. The plan uses a combination of advanced technology and infrastructure upgrades to improve service to customers and provide them with better information about their energy use. It also provides for cost recovery through a transmission and distribution rider (T&D Rider). In March 2016, Duke Energy Indiana entered into a settlement with all parties to the proceeding except the Citizens Action Coalition of Indiana, Inc. The settlement agreement decreased the capital expenditures eligible for timely recovery of costs in the seven-year plan to approximately $1.4 billion, including the removal of an AMI project. Under the settlement, the return on equity to be used in the T&D Rider is 10 percent. The IURC approved the settlement and issued a final order on June 29, 2016. The order was not appealed and the proceeding is concluded.

The settlement agreement provided for deferral accounting for depreciation and post-in-service carrying costs for AMI projects outside the plan. Duke Energy Indiana withdrew its request for a regulatory asset for current meters and will retain any savings associated with future AMI installation until the next retail base rate case, which is required to be filed prior to the end of the plan. During the third quarter of 2016, Duke Energy Indiana decided to implement the AMI project. This decision resulted in a pretax impairment charge related to existing or non-AMI meters of approximately $8 million in 2016, based in part on the requirement to file a base rate case in 2022 under the approved plan. Duke Energy Indiana evaluates the need for rate cases as part of its business planning, based on the outlook of emerging costs, ongoing investment and impact related to the Tax Act enacted in late 2017 and expects to file a rate case prior to the 2022 requirement. As a result, in 2017, Duke Energy Indiana recorded an additional impairment charge of approximately $22 million. As of December 31, 2017, Duke Energy Indiana's remaining net book value of non-AMI meters is approximately $21 million and will be depreciated through July 2020.

Benton County Wind Farm Dispute

On December 16, 2013, Benton County Wind Farm LLC (BCWF) filed a lawsuit against Duke Energy Indiana seeking damages for past generation losses alleging Duke Energy Indiana violated its obligations under a 2006 PPA by refusing to offer electricity to the market at negative prices. Damage claims continue to increase during times that BCWF is not dispatched. Under 2013 revised MISO market rules, Duke Energy Indiana is required to make a price offer to MISO for the power it proposes to sell into MISO markets and MISO determines whether BCWF is dispatched. Because market prices would have been negative due to increased market participation, Duke Energy Indiana determined it would not bid at negative prices in order to balance customer needs against BCWF's need to run. BCWF contends Duke Energy Indiana must bid at the lowest negative price to ensure dispatch, while Duke Energy Indiana contends it is not obligated to bid at any particular price, that it cannot ensure dispatch with any bid and that it has reasonably balanced the parties' interests. On July 6, 2015, the U.S. District Court for the Southern District of Indiana entered judgment against BCWF on all claims. BCWF appealed the decision and on December 9, 2016, the appeals court ruled in favor of BCWF. Duke Energy Indiana recorded an obligation and a regulatory asset related to the settlement amount in fourth quarter 2016. On June 30, 2017, the parties finalized a settlement agreement. Terms of the settlement included Duke Energy Indiana paying $29 million for back damages. Additionally, the parties agreed on the method by which the contract will be bid into the market in the future. The settlement amount was paid in June 2017. The IURC issued an order on September 27, 2017, approving recovery of the settlement amount through Duke Energy Indiana's fuel clause. The IURC order has been appealed to the Indiana Court of Appeals. Duke Energy Indiana cannot predict the outcome of this matter.

Piedmont

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Piedmont's Consolidated Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2017**	**2016**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs - other	**$ 15**	$ 14		(d)
Accrued pension and OPEB[c]	**91**	166		(f)
Derivatives - gas supply contracts	**142**	187		(e)
Vacation accrual[c]	**10**	13		2018
Deferred pipeline integrity costs[c]	**42**	36		2018
Amount due from customers	**64**	66	X	(b)
Other	**14**	15		(b)
Total regulatory assets	**378**	497		
Less: current portion	**95**	124		
Total noncurrent regulatory assets	**$ 283**	$ 373		
Regulatory Liabilities[a]				
Costs of removal	**$ 544**	$ 528		(d)
Net regulatory liability related to income taxes	**597**	80		(b)
Other	**3**	—		(b)
Total regulatory liabilities	**1,144**	608		
Less: current portion	**3**	—		
Total noncurrent regulatory liabilities	**$ 1,141**	$ 608		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Balance will fluctuate with changes in the market. Current contracts extend into 2031.

(f) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 21 for additional detail.

South Carolina Rate Stabilization Adjustment Filing

In June 2017, Piedmont filed with the PSCSC under the South Carolina Rate Stabilization Act its quarterly monitoring report for the 12-month period ending March 31, 2017. The filing included a revenue deficiency calculation and tariff rates in order to permit Piedmont the opportunity to earn the rate of return on equity of 12.6 percent established in its last general rate case. On October 4, 2017, the PSCSC approved a settlement agreement between Piedmont and the SC Office of Regulatory Staff. Terms of the settlement included implementation of rates for the 12-month period beginning November 2017 with a return on equity of 10.2 percent.

North Carolina Integrity Management Rider Filings

In October 2017, Piedmont filed a petition with the NCUC under the Integrity Management Rider (IMR) mechanism to collect an additional $8.9 million in annual revenues, effective December 2017, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending September 30, 2017. On November 28, 2017, the NCUC approved the requested rate adjustment.

In May 2017, Piedmont filed, and the NCUC approved, a petition under the IMR mechanism to collect an additional $11.6 million in annual revenues, effective June 2017, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending March 31, 2017.

Tennessee Integrity Management Rider Filing

In November 2017, Piedmont filed a petition with the TPUC under the IMR mechanism to collect an additional $3.3 million in annual revenues, effective January 2018, based on the eligible capital investments closed to integrity and safety projects over the 12-month period ending October 31, 2017. In January 2018, Piedmont filed an amended computation under the IMR mechanism, revising the proposed increase in annual revenues to approximately $0.4 million based on the decrease in the corporate federal income tax rate effective January 1, 2018. A hearing on this matter is scheduled for March 2018.

OTHER REGULATORY MATTERS

Atlantic Coast Pipeline

On September 2, 2014, Duke Energy, Dominion Resources (Dominion), Piedmont and Southern Company Gas announced the formation of Atlantic Coast Pipeline, LLC (ACP) to build and own the proposed Atlantic Coast Pipeline (ACP pipeline), an approximately 600-mile interstate natural gas pipeline running from West Virginia to North Carolina. The ACP pipeline is designed to meet, in part, the needs identified by Duke Energy Carolinas, Duke Energy Progress and Piedmont. Dominion will build and operate the ACP pipeline and holds a leading ownership percentage in ACP of 48 percent. Duke Energy owns a 47 percent interest through its Gas Utilities and Infrastructure segment. Southern Company Gas maintains a 5 percent interest. See Notes 12 and 17 for additional information related to Duke Energy's ownership interest.

Duke Energy Carolinas, Duke Energy Progress and Piedmont, among others, will be customers of the pipeline. Purchases will be made under several 20-year supply contracts, subject to state regulatory approval. On September 18, 2015, ACP filed an application with the FERC requesting a CPCN authorizing ACP to construct the pipeline. ACP executed a construction agreement in September 2016. ACP also requested approval of an open access tariff and the precedent agreements it entered into with future pipeline customers. In December 2016, FERC issued a draft Environmental Impact Statement (EIS) indicating that the proposed pipeline would not cause significant harm to the environment or protected populations. The FERC issued the final EIS in July 2017. On October 13, 2017, FERC issued an order approving the CPCN, subject to conditions. On October 16, 2017, ACP accepted the FERC order subject to reserving its right to file a request for rehearing or clarification on a timely basis. On November 9, 2017, ACP filed a request for rehearing on several limited issues. On December 12, 2017, ACP filed an answer to intervenors' request for rehearing of the certificate order and for stay of the certificate order.

In December 2017, West Virginia issued a waiver of the state water quality permit in reliance on the U.S. Army Corps of Engineers national water quality permit and Virginia issued a conditional water quality permit subject to completion of additional studies and stormwater plans. In early 2018, the FERC issued a series of Partial Notices to Proceed which authorized the project to begin limited construction-related activities along the pipeline route. North Carolina issued the state water quality permit in January 2018. The project remains subject to other pending federal and state approvals, which will allow full construction activities to begin. The ACP pipeline project has a targeted in-service date of late 2019.

Due to delays in obtaining the required permits to commence construction and the conditions imposed upon the project by the permits, ACP's project manager estimates the project's pipeline development costs have increased from a range of $5.0 billion to $5.5 billion to a range of $6.0 billion and $6.5 billion, excluding financing costs. Project construction activities, schedule and final costs are still subject to uncertainty due to potential additional permitting delays, construction productivity and other conditions and risks which could result in potential higher project costs and a potential delay in the targeted in-service date.

Sabal Trail Transmission Pipeline

On May 4, 2015, Duke Energy acquired a 7.5 percent ownership interest in Sabal Trail Transmission, LLC (Sabal Trail) from Spectra Energy Partners, LP, a master limited partnership, formed by Enbridge Inc. (formerly Spectra Energy Corp.). Spectra Energy Partners, LP holds a 50 percent ownership interest in Sabal Trail and NextEra Energy has a 42.5 percent ownership interest. Sabal Trail is a joint venture to construct a 515-mile natural gas pipeline (Sabal Trail pipeline) to transport natural gas to Florida. Total estimated project costs are approximately $3.2 billion. The Sabal Trail pipeline traverses Alabama, Georgia and Florida. The primary customers of the Sabal Trail pipeline, Duke Energy Florida and Florida Power & Light Company (FP&L), have each contracted to buy pipeline capacity for 25-year initial terms. See Notes 12 and 17 for additional information.

On February 3, 2016, the FERC issued an order granting the request for a CPCN to construct and operate the pipeline. The Sabal Trail pipeline received other required regulatory approvals and the phase one mainline was placed in service in July 2017. On October 12, 2017, Sabal Trail filed a request with FERC to place in-service a lateral line to Duke Energy Florida's Citrus County Combined Cycle facility, which remains pending. This request is required to support commissioning and testing activities at the facility.

On September 21, 2016, intervenors filed an appeal of FERC's CPCN orders to the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals). On August 22, 2017, the appeals court ruled against FERC in the case for failing to include enough information on the impact of greenhouse-gas emissions carried by the pipeline, vacated the CPCN order and remanded the case to FERC. In response to the August 2017 court decision, the FERC issued a draft Supplemental Environmental Impact Statement (SEIS) on September 27, 2017. On October 6, 2017, FERC and a group of industry intervenors, including Sabal Trail and Duke Energy Florida, filed separate petitions with the D.C. Circuit Court of Appeals requesting rehearing regarding the court's decision to vacate the CPCN order. On January 31, 2018, the D.C. Circuit Court of Appeals denied the requests for rehearing. On February 2, 2018, Sabal Trail filed a request with FERC for expedited issuance of its order on remand and reissuance of the CPCN. In the alternative, the pipeline requested that FERC issue a temporary emergency CPCN to allow for continued operations. On February 5, 2018, FERC issued the final SEIS but did not issue the order on remand. On February 6, 2018, FERC and the intervenors in this case each filed motions for stay with the D.C. Circuit Court to stay the court's mandate. The February 6, 2018 motions automatically stay the issuance of the court’s mandate until the later of seven days after the court denies the motions or the expiration of any stay granted by the court. Both motions are pending. Sabal Trail will continue to monitor the progress and the impact to the project going forward.

Constitution Pipeline

Duke Energy owns a 24 percent ownership interest in Constitution Pipeline Company, LLC (Constitution). Constitution is a natural gas pipeline project slated to transport natural gas supplies from the Marcellus supply region in northern Pennsylvania to major northeastern markets. The pipeline will be constructed and operated by Williams Partners L.P., which has a 41 percent ownership share. The remaining interest is held by Cabot Oil and Gas Corporation and WGL Holdings, Inc. Before the permitting delays discussed below, Duke Energy's total anticipated contributions were approximately $229 million. As a result of the permitting delays and project uncertainty, total anticipated contributions by Duke Energy can no longer be reasonably estimated.

In December 2014, Constitution received approval from the FERC to construct and operate the proposed pipeline. However, on April 22, 2016, the New York State Department of Environmental Conservation (NYSDEC) denied Constitution's application for a necessary water quality certification for the New York portion of the Constitution pipeline. Constitution filed legal actions in the U.S. Court of Appeals for the Second Circuit (U.S. Court of Appeals) challenging the legality and appropriateness of the NYSDEC's decision and on August 18, 2017, the petition was denied in part and dismissed in part. In September 2017, Constitution filed a petition for a rehearing of portions of the decision unrelated to the water quality certification, which was denied by the U.S. Court of Appeals. In January 2018, Constitution petitioned the Supreme Court of the United States to review the U.S. Court of Appeals decision. In October 2017, Constitution filed a petition for declaratory order requesting FERC to find that the NYSDEC waived its rights to issue a Section 401 water quality certification by not acting on Constitution's application within a reasonable period of time as required by statute. This petition was based on precedent established by another pipeline's successful petition with FERC following a District of Columbia Circuit Court ruling. On January 11, 2018, FERC denied Constitution's petition. In February 2018, Constitution filed a rehearing request with FERC of its finding that the NYSDEC did not waive the Section 401 certification requirement. Constitution is currently unable to approximate an in-service date for the project due to the NYDSEC's denial of the water quality certification. The Constitution partners remain committed to the project and are evaluating next steps to move the project forward. Duke Energy cannot predict the outcome of this matter.

Since April 2016, with the actions of the NYSDEC, Constitution stopped construction and discontinued capitalization of future development costs until the project's uncertainty is resolved.

See Notes 12 and 17 for additional information related to ownership interest and carrying value of the investment.

Progress Energy Merger FERC Mitigation

Following the closing of the Progress Energy merger, outside counsel reviewed Duke Energy's long-term FERC mitigation plan and discovered a technical error in the calculations. On December 6, 2013, Duke Energy submitted a filing to the FERC disclosing the error and arguing that no additional mitigation is necessary. The city of New Bern filed a protest and requested that FERC order additional mitigation. On October 29, 2014, the FERC ordered that the amount of the stub mitigation be increased from 25 MW to 129 MW. The stub mitigation is Duke Energy's commitment to set aside for third parties a certain quantity of firm transmission capacity from Duke Energy Carolinas to Duke Energy Progress during summer off-peak hours. The FERC also ordered that Duke Energy operate certain phase shifters to create additional import capability and that such operation be monitored by an independent monitor. The costs to comply with this order are not material. The FERC also referred Duke Energy's failure to expressly designate the phase shifter reactivation as a mitigation project in the original mitigation plan filing in March 2012 to the FERC Office of Enforcement for further inquiry. In response, and since December 2014, the FERC Office of Enforcement has been conducting a nonpublic investigation of Duke Energy's market power analyses included in the Progress merger filings submitted to FERC. Duke Energy cannot predict the outcome of this investigation.

Potential Coal Plant Retirements

The Subsidiary Registrants periodically file Integrated Resource Plans (IRP) with their state regulatory commissions. The IRPs provide a view of forecasted energy needs over a long term (10 to 20 years) and options being considered to meet those needs. Recent IRPs filed by the Subsidiary Registrants included planning assumptions to potentially retire certain coal-fired generating facilities in Florida and Indiana earlier than their current estimated useful lives primarily because facilities do not have the requisite emission control equipment to meet EPA regulations recently approved or proposed.

The table below contains the net carrying value of generating facilities planned for retirement or included in recent IRPs as evaluated for potential retirement due to a lack of requisite environmental control equipment. Dollar amounts in the table below are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2017, and exclude capitalized asset retirement costs.

	Capacity (in MW)	Remaining Net Book Value (in millions)
Duke Energy Carolinas		
Allen Steam Station Units 1-3[(a)]	**585**	**$ 163**
Progress Energy and Duke Energy Florida		
Crystal River Units 1 and 2[(b)]	**873**	**107**
Duke Energy Indiana		
Gallagher Units 2 and 4[(c)]	**280**	**127**
Total Duke Energy	**1,738**	**$ 397**

(a) Duke Energy Carolinas will retire Allen Steam Station Units 1 through 3 by December 31, 2024, as part of the resolution of a lawsuit involving alleged New Source Review violations.
(b) Duke Energy Florida expects to retire these coal units by the end of 2018 to comply with environmental regulations.
(c) Duke Energy Indiana committed to either retire or stop burning coal at Gallagher Units 2 and 4 by December 31, 2022, as part of the settlement of Edwardsport IGCC matters.

Refer to the "Western Carolinas Modernization Plan" discussion above for details of Duke Energy Progress' planned retirements.

5. COMMITMENTS AND CONTINGENCIES

INSURANCE

General Insurance

The Duke Energy Registrants have insurance and reinsurance coverage either directly or through indemnification from Duke Energy’s captive insurance company, Bison, and its affiliates, consistent with companies engaged in similar commercial operations with similar type properties. The Duke Energy Registrants’ coverage includes (i) commercial general liability coverage for liabilities arising to third parties for bodily injury and property damage; (ii) workers’ compensation; (iii) automobile liability coverage; and (iv) property coverage for all real and personal property damage. Real and personal property damage coverage excludes electric transmission and distribution lines, but includes damages arising from boiler and machinery breakdowns, earthquakes, flood damage and extra expense, but not outage or replacement power coverage. All coverage is subject to certain deductibles or retentions, sublimits, exclusions, terms and conditions common for companies with similar types of operations. The Duke Energy Registrants self-insure their electric transmission and distribution lines against loss due to storm damage and other natural disasters. As discussed further in Note 4, Duke Energy Florida maintains a storm damage reserve and has a regulatory mechanism to recover the cost of named storms on an expedited basis.

The cost of the Duke Energy Registrants’ coverage can fluctuate from year to year reflecting claims history and conditions of the insurance and reinsurance markets.

In the event of a loss, terms and amounts of insurance and reinsurance available might not be adequate to cover claims and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material effect on the Duke Energy Registrants’ results of operations, cash flows or financial position. Each company is responsible to the extent losses may be excluded or exceed limits of the coverage available.

Nuclear Insurance

Duke Energy Carolinas owns and operates the McGuire Nuclear Station (McGuire) and the Oconee Nuclear Station (Oconee) and operates and has a partial ownership interest in the Catawba Nuclear Station (Catawba). McGuire and Catawba each have two reactors. Oconee has three reactors. The other joint owners of Catawba reimburse Duke Energy Carolinas for certain expenses associated with nuclear insurance per the Catawba joint owner agreements.

Duke Energy Progress owns and operates the Robinson Nuclear Plant (Robinson), Brunswick and Harris. Robinson and Harris each have one reactor. Brunswick has two reactors.

Duke Energy Florida owns Crystal River Unit 3, which permanently ceased operation in 2013 and reached a SAFSTOR condition in January 2018 after the successful transfer of all used nuclear fuel assemblies to an onsite dry cask storage facility.

In the event of a loss, terms and amounts of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material effect on Duke Energy Carolinas’, Duke Energy Progress’ and Duke Energy Florida’s results of operations, cash flows or financial position. Each company is responsible to the extent losses may be excluded or exceed limits of the coverage available.

Nuclear Liability Coverage

The Price-Anderson Act requires owners of nuclear reactors to provide for public nuclear liability protection per nuclear incident up to a maximum total financial protection liability. The maximum total financial protection liability, which is approximately $13.4 billion, is subject to change every five years for inflation and for the number of licensed reactors. Total nuclear liability coverage consists of a combination of private primary nuclear liability insurance coverage and a mandatory industry risk-sharing program to provide for excess nuclear liability coverage above the maximum reasonably available private primary coverage. The U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims.

Primary Liability Insurance

Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida have purchased the maximum reasonably available private primary nuclear liability insurance as required by law, which is $450 million per station.

Excess Liability Program

This program provides $13 billion of coverage per incident through the Price-Anderson Act’s mandatory industrywide excess secondary financial protection program of risk pooling. This amount is the product of potential cumulative retrospective premium assessments of $127 million times the current 102 licensed commercial nuclear reactors in the U.S. Under this program, licensees could be assessed retrospective premiums to compensate for public nuclear liability damages in the event of a nuclear incident at any licensed facility in the U.S. Retrospective premiums may be assessed at a rate not to exceed $19 million per year per licensed reactor for each incident. The assessment may be subject to state premium taxes.

Nuclear Property and Accidental Outage Coverage

Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are members of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company, which provides property damage, nuclear accident decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Additionally, NEIL provides accidental outage coverage for each station for losses in the event of a major accidental outage at an insured nuclear station.

Pursuant to regulations of the NRC, each company’s property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after a qualifying accident and second, to decontaminate the plant before any proceeds can be used for decommissioning, plant repair or restoration.

Losses resulting from acts of terrorism are covered as common occurrences, such that if terrorist acts occur against one or more commercial nuclear power plants insured by NEIL within a 12-month period, they would be treated as one event and the owners of the plants where the act occurred would share one full limit of liability. The full limit of liability is currently $3.2 billion. NEIL sublimits the total aggregate for all of their policies for non-nuclear terrorist events to approximately $1.83 billion.

Each nuclear facility has accident property damage, decontamination and premature decommissioning liability insurance from NEIL with limits of $1.5 billion, except for Crystal River Unit 3. Crystal River Unit 3’s limit is $50 million and is on an actual cash value basis. All nuclear facilities except for Catawba and Crystal River Unit 3 also share an additional $1.25 billion nuclear accident insurance limit above their dedicated underlying limit. This shared additional excess limit is not subject to reinstatement in the event of a loss. Catawba has a dedicated $1.25 billion of additional nuclear accident insurance limit above its dedicated underlying limit. Catawba and Oconee also have an additional $750 million of non-nuclear accident property damage limit. All coverages are subject to sublimits and significant deductibles.

NEIL’s Accidental Outage policy provides some coverage, such as business interruption, for losses in the event of a major accident property damage outage of a nuclear unit. Coverage is provided on a weekly limit basis after a significant waiting period deductible and at 100 percent of the available weekly limits for 52 weeks and 80 percent of the available weekly limits for the next 110 weeks. Coverage is provided until these available weekly periods are met where the accidental outage policy limit will not exceed $490 million for McGuire and Catawba, $462 million for Brunswick, $448 million for Harris, $434 million for Oconee and $378 million for Robinson. NEIL sublimits the accidental outage recovery to the first 104 weeks of coverage not to exceed $328 million from non-nuclear accidental property damage. Coverage amounts decrease in the event more than one unit at a station is out of service due to a common accident. All coverages are subject to sublimits and significant deductibles.

Potential Retroactive Premium Assessments

In the event of NEIL losses, NEIL’s board of directors may assess member companies' retroactive premiums of amounts up to 10 times their annual premiums for up to six years after a loss. NEIL has never exercised this assessment. The maximum aggregate annual retrospective premium obligations for Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are $146 million, $96 million and $1 million, respectively. Duke Energy Carolinas' maximum assessment amount includes 100 percent of potential obligations to NEIL for jointly owned reactors. Duke Energy Carolinas would seek reimbursement from the joint owners for their portion of these assessment amounts.

ENVIRONMENTAL

The Duke Energy Registrants are subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations can be changed from time to time, imposing new obligations on the Duke Energy Registrants. The following environmental matters impact all of the Duke Energy Registrants.

Remediation Activities

In addition to the ARO recorded as a result of various environmental regulations, discussed in Note 9, the Duke Energy Registrants are responsible for environmental remediation at various sites. These include certain properties that are part of ongoing operations and sites formerly owned or used by Duke Energy entities. These sites are in various stages of investigation, remediation and monitoring. Managed in conjunction with relevant federal, state and local agencies, remediation activities vary based upon site conditions and location, remediation requirements, complexity and sharing of responsibility. If remediation activities involve joint and several liability provisions, strict liability, or cost recovery or contribution actions, the Duke Energy Registrants could potentially be held responsible for environmental impacts caused by other potentially responsible parties and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. Liabilities are recorded when losses become probable and are reasonably estimable. The total costs that may be incurred cannot be estimated because the extent of environmental impact, allocation among potentially responsible parties, remediation alternatives and/or regulatory decisions have not yet been determined at all sites. Additional costs associated with remediation activities are likely to be incurred in the future and could be significant. Costs are typically expensed as Operation, maintenance and other in the Consolidated Statements of Operations unless regulatory recovery of the costs is deemed probable.

The following tables contain information regarding reserves for probable and estimable costs related to the various environmental sites. These reserves are recorded in Accounts payable within Current Liabilities and Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Balance at December 31, 2014	$ 92	$ 10	$ 17	$ 5	$ 12	$ 54	$ 10
Provisions/adjustments	11	1	4	—	4	1	5
Cash reductions	(9)	(1)	(4)	(2)	(2)	(1)	(3)
Balance at December 31, 2015	94	10	17	3	14	54	12
Provisions/adjustments	19	4	7	2	4	7	1
Cash reductions	(15)	(4)	(6)	(2)	(4)	(2)	(3)
Balance at December 31, 2016	98	10	18	3	14	59	10
Provisions/adjustments	**8**	**3**	**3**	**2**	**2**	**3**	**(4)**
Cash reductions	**(25)**	**(3)**	**(6)**	**(2)**	**(4)**	**(15)**	**(1)**
Balance at December 31, 2017	**$ 81**	**$ 10**	**$ 15**	**$ 3**	**$ 12**	**$ 47**	**$ 5**

As of December 31, 2016, October 31, 2016, 2015 and 2014, Piedmont's environmental reserve was $1 million. In 2017, a $1 million provision was recorded, resulting in a reserve balance of $2 million at December 31, 2017.

Additional losses in excess of recorded reserves that could be incurred for the stages of investigation, remediation and monitoring for environmental sites that have been evaluated at this time are not material except as presented in the table below.

(in millions)		
Duke Energy	**$**	**56**
Duke Energy Carolinas		**19**
Duke Energy Ohio		**30**
Piedmont		**2**

North Carolina and South Carolina Ash Basins

In February 2014, a break in a stormwater pipe beneath an ash basin at Duke Energy Carolinas' retired Dan River Steam Station caused a release of ash basin water and ash into the Dan River. Duke Energy Carolinas estimates 30,000 to 39,000 tons of ash and 24 million to 27 million gallons of basin water were released into the river. In July 2014, Duke Energy completed remediation work identified by the EPA and continues to cooperate with the EPA's civil enforcement process. Future costs related to the Dan River release, including future state or federal civil enforcement proceedings, future regulatory directives, natural resources damages, future claims or litigation and long-term environmental impact costs, cannot be reasonably estimated at this time.

The North Carolina Department of Environmental Quality (NCDEQ) has historically assessed Duke Energy Carolinas and Duke Energy Progress with Notice of Violations (NOV) for violations that were most often resolved through satisfactory corrective actions and minor, if any, fines or penalties. Subsequent to the Dan River ash release, Duke Energy Carolinas and Duke Energy Progress have been served with a higher level of NOVs, including assessed penalties for violations at L.V. Sutton Combined Cycle Plant (Sutton) and Dan River Steam Station. Duke Energy Carolinas and Duke Energy Progress cannot predict whether the NCDEQ will assess future penalties related to existing unresolved NOVs and if such penalties would be material. See "NCDEQ Notices of Violation" section below for additional discussion.

LITIGATION

Duke Energy

Duke Energy no longer has exposure to litigation matters related to the International Disposal Group as a result of the divestiture of the business in December 2016. See Note 2 for additional information related to the sale of International Energy.

Ash Basin Shareholder Derivative Litigation

Five shareholder derivative lawsuits were filed in Delaware Chancery Court relating to the release at Dan River and to the management of Duke Energy's ash basins. On October 31, 2014, the five lawsuits were consolidated in a single proceeding titled *In Re Duke Energy Corporation Coal Ash Derivative Litigation*. On December 2, 2014, plaintiffs filed a Corrected Verified Consolidated Shareholder Derivative Complaint (Consolidated Complaint). The Consolidated Complaint names as defendants several current and former Duke Energy officers and directors (collectively, the "Duke Energy Defendants"). Duke Energy is named as a nominal defendant.

The Consolidated Complaint alleges the Duke Energy Defendants breached their fiduciary duties by failing to adequately oversee Duke Energy's ash basins and that these breaches of fiduciary duty may have contributed to the incident at Dan River and continued thereafter. The lawsuit also asserts claims against the Duke Energy Defendants for corporate waste (relating to the money Duke Energy has spent and will spend as a result of the fines, penalties and coal ash removal) and unjust enrichment (relating to the compensation and director remuneration that was received despite these alleged breaches of fiduciary duty). The lawsuit seeks both injunctive relief against Duke Energy and restitution from the Duke Energy Defendants. On January 21, 2015, the Duke Energy Defendants filed a Motion to Stay, which the court granted. The stay was lifted on March 24, 2016, after which plaintiffs filed an Amended Verified Consolidated Shareholder Derivative Complaint (Amended Complaint) making the same allegations as in the Consolidated Complaint. The Duke Energy Defendants filed a motion to dismiss the Amended Complaint on June 21, 2016, which was granted by the Court on December 14, 2016. Plaintiffs filed an appeal to the Delaware Supreme Court on January 9, 2017. Oral argument was held on September 27, 2017. On December 15, 2017, the Delaware Supreme Court affirmed the Chancery Court's order of dismissal.

In addition to the above derivative complaints, in 2014, Duke Energy received two shareholder litigation demand letters. The letters alleged that the members of the Board of Directors and certain officers breached their fiduciary duties by allowing the company to illegally dispose of and store coal ash pollutants. One of the letters also alleged a breach of fiduciary duty in the decision-making relating to the leadership changes following the close of the Progress Energy merger in July 2012. By letter dated September 4, 2015, attorneys for the shareholders were informed that, on the recommendation of the Demand Review Committee formed to consider such matters, the Board of Directors concluded not to pursue potential claims against individuals. One of the shareholders, Mitchell Pinsly, sent a formal demand for records and Duke Energy has responded to this request. There was no follow-up after the records were provided; therefore, this matter has been resolved.

On October 30, 2015, shareholder Saul Bresalier filed a shareholder derivative complaint (Bresalier Complaint) in the U.S. District Court for the District of Delaware. The lawsuit alleges that several current and former Duke Energy officers and directors (Bresalier Defendants) breached their fiduciary duties in connection with coal ash environmental issues, the post-merger change in Chief Executive Officer (CEO) and oversight of political contributions. Duke Energy is named as a nominal defendant. The Bresalier Complaint contends that the Demand Review Committee failed to appropriately consider the shareholder's earlier demand for litigation and improperly decided not to pursue claims against the Bresalier Defendants. On March 30, 2017, the court granted Defendants' Motion to Dismiss on the claims relating to coal ash environmental issues and political contributions. As discussed below, a settlement agreement was approved for the merger-related claims in the Bresalier Complaint, and those claims were dismissed. On September 8, 2017, Bresalier filed a notice of appeal to the U.S. Court of Appeals for the Third Circuit (Third Circuit Court) challenging the dismissal of his coal ash and political contribution claims. On January 19 2018, Bresalier filed a stipulation of dismissal, closing this case.

Progress Energy Merger Shareholder Litigation

Duke Energy, the 11 members of the Board of Directors who were also members of the pre-merger Board of Directors (Legacy Duke Energy Directors) and certain Duke Energy officers were defendants in a purported securities class-action lawsuit *(Nieman v. Duke Energy Corporation, et al)*. This lawsuit consolidated three lawsuits originally filed in July 2012. The plaintiffs alleged federal Securities Act of 1933 and Securities Exchange Act of 1934 (Exchange Act) claims based on allegations of materially false and misleading representations and omissions in the Registration Statement filed on July 7, 2011, and purportedly incorporated into other documents, all in connection with the post-merger change in CEO. On August 15, 2014, the parties reached an agreement in principle to settle the litigation. On March 10, 2015, the parties filed a Stipulation of Settlement and a Motion for Preliminary Approval of the Settlement. Under the terms of the agreement, Duke Energy agreed to pay $146 million to settle the claim. On April 22, 2015, Duke Energy made a payment of $25 million into the settlement escrow account. The remainder of $121 million was paid by insurers into the settlement escrow account. The final order approving the settlement was issued on November 2, 2015, thus closing the matter.

On May 31, 2013, the Delaware Chancery Court consolidated four shareholder derivative lawsuits filed in 2012. The Court also appointed a lead plaintiff and counsel for plaintiffs and designated the case as *In Re Duke Energy Corporation Derivative Litigation* (Merger Chancery Litigation). The lawsuit names as defendants the Legacy Duke Energy Directors. Duke Energy is named as a nominal defendant. The case alleges claims for breach of fiduciary duties of loyalty and care in connection with the post-merger change in CEO.

Two shareholder Derivative Complaints, filed in 2012 in federal district court in Delaware, were consolidated as *Tansey v. Rogers, et al.* The case alleges claims against the Legacy Duke Energy Directors for breach of fiduciary duty and waste of corporate assets, as well as claims under Section 14(a) and 20(a) of the Exchange Act. Duke Energy is named as a nominal defendant. On December 21, 2015, Plaintiff filed a Consolidated Amended Complaint asserting the same claims contained in the original complaints.

The Legacy Duke Energy Directors have reached an agreement-in-principle to settle the Merger Chancery Litigation, conditioned on dismissal as well, of the *Tansey v. Rogers, et al* case and the merger related claims in the Bresalier Complaint discussed above, which was approved by the Delaware Chancery Court on July 13, 2017. The entire settlement amount was funded by insurance. The settlement amount, less court-approved attorney fees, totaled $20 million and was paid to Duke Energy in 2017.

Duke Energy Carolinas and Duke Energy Progress

Coal Ash Insurance Coverage Litigation

In March 2017, Duke Energy Carolinas and Duke Energy Progress filed a civil action in North Carolina Superior Court against various insurance providers. The lawsuit seeks payment for coal ash-related liabilities covered by third-party liability insurance policies. The insurance policies were issued between 1971 and 1986 and provide third-party liability insurance for property damage. The civil action seeks damages for breach of contract and indemnification for costs arising from the Coal Ash Act and the EPA CCR rule at 15 coal-fired plants in North Carolina and South Carolina. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

NCDEQ Notice of Violation

On February 8, 2016, the NCDEQ assessed a penalty of approximately $6.8 million, including enforcement costs, against Duke Energy Carolinas related to stormwater pipes and associated discharges at the Dan River Steam Station. Duke Energy Carolinas recorded a charge in December 2015 for this penalty. In March 2016, Duke Energy Carolinas filed an appeal of this penalty. On September 23, 2016, Duke Energy Carolinas entered into a settlement agreement with the NCDEQ, without admission of liability, under which Duke Energy Carolinas agreed to a payment of $6 million to resolve allegations underlying the asserted civil penalty related to the Dan River coal ash release and a March 4, 2016, NOV alleging unpermitted discharges at the facility.

NCDEQ State Enforcement Actions

In the first quarter of 2013, Southern Environmental Law Center (SELC) sent notices of intent to sue Duke Energy Carolinas and Duke Energy Progress related to alleged Clean Water Act (CWA) violations from coal ash basins at two of their coal-fired power plants in North Carolina. The NCDEQ filed enforcement actions against Duke Energy Carolinas and Duke Energy Progress alleging violations of water discharge permits and North Carolina groundwater standards. The cases have been consolidated and are being heard before a single judge in the North Carolina Superior Court.

On August 16, 2013, the NCDEQ filed an enforcement action against Duke Energy Carolinas and Duke Energy Progress related to their remaining plants in North Carolina alleging violations of the CWA and violations of the North Carolina groundwater standards. Both of these cases have been assigned to the judge handling the enforcement actions discussed above. SELC is representing several environmental groups who have been permitted to intervene in these cases.

The court issued orders in 2016 granting Motions for Partial Summary Judgment for seven of the 14 North Carolina plants with coal ash basins named in the enforcement actions. On February 13, 2017, the court issued an order denying motions for partial summary judgment brought by both the environmental groups and Duke Energy Carolinas and Duke Energy Progress for the remaining seven plants. On March 15, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Notice of Appeal to challenge the trial court’s order. The parties were unable to reach an agreement at mediation in April 2017. The parties submitted briefs to the court on remaining issues to be tried and a ruling is pending. On August 22, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Petition for Discretionary Review, requesting the North Carolina Supreme Court to accept the appeal. On August 24, 2017, SELC filed a motion to dismiss the appeal. Duke Energy Carolinas' and Duke Energy Progress’ opening appellate briefs were filed on October 12, 2017, and briefing is now complete. Argument was held on February 8, 2018.

It is not possible to predict any liability or estimate any damages Duke Energy Carolinas or Duke Energy Progress might incur in connection with these matters.

Federal Citizens Suits

On June 13, 2016, the Roanoke River Basin Association (RRBA) filed a federal citizen suit in the Middle District of North Carolina alleging unpermitted discharges to surface water and groundwater violations at the Mayo Plant. On August 19, 2016, Duke Energy Progress filed a Motion to Dismiss. On April 26, 2017, the court entered an order dismissing four of the claims in the federal citizen suit. Two claims relating to alleged violations of National Pollutant Discharge Elimination System (NPDES) permit provisions survived the motion to dismiss, and Duke Energy Progress filed its response on May 10, 2017. The parties are engaged in pre-trial discovery. Trial has been scheduled for July 9, 2018.

On March 16, 2017, RRBA served Duke Energy Progress with a Notice of Intent to Sue under the CWA for alleged violations of effluent standards and limitations at the Roxboro Plant. In anticipation of litigation, Duke Energy Progress filed a Complaint for Declaratory Relief in the U.S. District Court for the Western District of Virginia on May 11, 2017, which was subsequently dismissed. On May 16, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina which asserts two claims relating to alleged violations of NPDES permit provisions and one claim relating to the use of nearby water bodies. The parties are engaged in pre-trial discovery. Trial has been scheduled for October 1, 2018.

On June 20, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina challenging the closure plans at the Mayo Plant under the EPA CCR Rule. Duke Energy Progress filed a motion to dismiss, which was argued on January 30, 2018.

On August 2, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina challenging the closure plans at the Roxboro Plant under the EPA CCR Rule. Duke Energy Progress filed a motion to dismiss on October 2, 2017.

On December 6, 2017, various parties filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina for alleged violations at Duke Energy Carolinas' Belews Creek Steam Station (Belews Creek) under the CWA. Duke Energy Carolinas filed a motion to dismiss on February 5, 2018.

It is not possible to predict whether Duke Energy Carolinas or Duke Energy Progress will incur any liability or to estimate the damages, if any, they might incur in connection with these matters.

Five previously filed cases involving the Riverbend, Cape Fear, H.F. Lee, Sutton and Buck plants have been dismissed or settled during 2016.

Groundwater Contamination Claims

Beginning in May 2015, a number of residents living in the vicinity of the North Carolina facilities with ash basins received letters from the NCDEQ advising them not to drink water from the private wells on their land tested by the NCDEQ as the samples were found to have certain substances at levels higher than the criteria set by the North Carolina Department of Health and Human Services (DHHS). Results of Comprehensive Site Assessments (CSAs) testing performed by Duke Energy under the Coal Ash Act have been consistent with historical data provided to state regulators over many years. The DHHS and NCDEQ sent follow-up letters on October 15, 2015, to residents near coal ash basins who have had their wells tested, stating that private well samplings at a considerable distance from coal ash basins, as well as some municipal water supplies, contain similar levels of vanadium and hexavalent chromium, which led investigators to believe these constituents are naturally occurring. In March 2016, DHHS rescinded the advisories.

Duke Energy Carolinas and Duke Energy Progress have received formal demand letters from residents near Duke Energy Carolinas' and Duke Energy Progress' coal ash basins. The residents claim damages for nuisance and diminution in property value, among other things. The parties held three days of mediation discussions which ended at impasse. On January 6, 2017, Duke Energy Carolinas and Duke Energy Progress received the plaintiffs' notice of their intent to file suits should the matter not settle. The NCDEQ preliminarily approved Duke Energy's permanent water solution plans on January 13, 2017, and as a result shortly thereafter, Duke Energy issued a press release, providing additional details regarding the homeowner compensation package. This package consists of three components: (i) a $5,000 goodwill payment to each eligible well owner to support the transition to a new water supply, (ii) where a public water supply is available and selected by the eligible well owner, a stipend to cover 25 years of water bills and (iii) the Property Value Protection Plan. The Property Value Protection Plan is a program offered by Duke Energy designed to guarantee eligible plant neighbors the fair market value of their residential property should they decide to sell their property during the time that the plan is offered. Duke Energy Carolinas and Duke Energy Progress recognized reserves of $19 million and $4 million, respectively.

On August 23, 2017, a class-action suit was filed in Wake County Superior Court, North Carolina, against Duke Energy Carolinas and Duke Energy Progress on behalf of certain property owners living near coal ash impoundments at Allen, Asheville, Belews Creek, Buck, Cliffside, Lee, Marshall, Mayo and Roxboro. The class is defined as those who are well-eligible under the Coal Ash Act or those to whom Duke Energy has promised a permanent replacement water supply and seeks declaratory and injunctive relief, along with compensatory damages. Plaintiffs allege that Duke Energy's improper maintenance of coal ash impoundments caused harm, particularly through groundwater contamination. Despite NCDEQ's preliminary approval, Plaintiffs contend that Duke Energy's proposed permanent water solutions plan fails to comply with the Coal Ash Act. On September 28, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Motion to Dismiss and Motion to Strike the class designation. The parties entered into a Settlement Agreement on January 24, 2018, which resulted in the dismissal of the underlying class action on January 25, 2018.

On September 14, 2017, a complaint was filed against Duke Energy Progress in New Hanover County Superior Court by a group of homeowners residing approximately 1 mile from Duke Energy Progress' Sutton Steam Plant. The homeowners allege that coal ash constituents have been migrating from ash impoundments at Sutton into their groundwater for decades and that in 2015, Duke Energy Progress discovered these releases of coal ash, but failed to notify any officials or neighbors and failed to take remedial action. The homeowners claim unspecified physical and mental injuries as a result of consuming their well water and seek actual damages for personal injury, medical monitoring and punitive damages. Duke Energy filed its Motion to Dismiss on October 27, 2017, and the hearing is scheduled for March 7, 2018.

It is not possible to estimate the maximum exposure of loss, if any, that may occur in connection with claims which might be made by these residents.

Duke Energy Carolinas

Asbestos-related Injuries and Damages Claims

Duke Energy Carolinas has experienced numerous claims for indemnification and medical cost reimbursement related to asbestos exposure. These claims relate to damages for bodily injuries alleged to have arisen from exposure to or use of asbestos in connection with construction and maintenance activities conducted on its electric generation plants prior to 1985. As of December 31, 2017, there were 161 asserted claims for non-malignant cases with the cumulative relief sought of up to $42 million and 54 asserted claims for malignant cases with the cumulative relief sought of up to $16 million. Based on Duke Energy Carolinas' experience, it is expected that the ultimate resolution of most of these claims likely will be less than the amount claimed.

Duke Energy Carolinas has recognized asbestos-related reserves of $489 million and $512 million at December 31, 2017, and 2016, respectively. These reserves are classified in Other within Other Noncurrent Liabilities and Other within Current Liabilities on the Consolidated Balance Sheets. These reserves are based upon the minimum amount of the range of loss for current and future asbestos claims through 2037, are recorded on an undiscounted basis and incorporate anticipated inflation. In light of the uncertainties inherent in a longer-term forecast, management does not believe they can reasonably estimate the indemnity and medical costs that might be incurred after 2037 related to such potential claims. It is possible Duke Energy Carolinas may incur asbestos liabilities in excess of the recorded reserves.

Duke Energy Carolinas has third-party insurance to cover certain losses related to asbestos-related injuries and damages above an aggregate self-insured retention. Duke Energy Carolinas' cumulative payments began to exceed the self-insurance retention in 2008. Future payments up to the policy limit will be reimbursed by the third-party insurance carrier. The insurance policy limit for potential future insurance recoveries indemnification and medical cost claim payments is $797 million in excess of the self-insured retention. Receivables for insurance recoveries were $585 million and $587 million at December 31, 2017, and 2016, respectively. These amounts are classified in Other within Other Noncurrent Assets and Receivables within Current Assets on the Consolidated Balance Sheets. Duke Energy Carolinas is not aware of any uncertainties regarding the legal sufficiency of insurance claims. Duke Energy Carolinas believes the insurance recovery asset is probable of recovery as the insurance carrier continues to have a strong financial strength rating.

Duke Energy Progress and Duke Energy Florida

Spent Nuclear Fuel Matters

On October 16, 2014, Duke Energy Progress and Duke Energy Florida sued the U.S. in the U.S. Court of Federal Claims. The lawsuit claimed the Department of Energy breached a contract in failing to accept spent nuclear fuel under the Nuclear Waste Policy Act of 1982 and asserted damages for the cost of on-site storage. Duke Energy Progress and Duke Energy Florida asserted damages for the period January 1, 2011, through December 31, 2013, of $48 million and $25 million, respectively. On November 17, 2017, the Court awarded Duke Energy Progress and Duke Energy Florida $48 million and $21 million, respectively, subject to appeal. No appeals were filed and Duke Energy Progress and Duke Energy Florida will recognize the recoveries in the first quarter of 2018. Claims for all periods through 2013 have been resolved. Additional claims will be filed in 2018.

Duke Energy Progress

Gypsum Supply Agreements Matter

On June 30, 2017, CertainTeed Gypsum NC, Inc. (CertainTeed) filed a declaratory judgment action against Duke Energy Progress in the North Carolina Business Court relating to a gypsum supply agreement. In its complaint, CertainTeed seeks an order from the court declaring that the minimum amount of gypsum Duke Energy Progress must provide to CertainTeed under the supply agreement is 50,000 tons per month through 2029. On September 28, 2017, the Court denied CertainTeed's motion for summary judgment. Discovery in the case is underway and a trial date has not been set. In light of the volatility in future production of gypsum, Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Florida

Class-Action Lawsuit

On February 22, 2016, a lawsuit was filed in the U.S. District Court for the Southern District of Florida on behalf of a putative class of Duke Energy Florida and FP&L's customers in Florida. The suit alleges the State of Florida's nuclear power plant cost recovery statutes (NCRS) are unconstitutional and pre-empted by federal law. Plaintiffs claim they are entitled to repayment of all money paid by customers of Duke Energy Florida and FP&L as a result of the NCRS, as well as an injunction against any future charges under those statutes. The constitutionality of the NCRS has been challenged unsuccessfully in a number of prior cases on alternative grounds. Duke Energy Florida and FP&L filed motions to dismiss the complaint on May 5, 2016. On September 21, 2016, the Court granted the motions to dismiss with prejudice. Plaintiffs filed a motion for reconsideration, which was denied. On January 4, 2017, plaintiffs filed a notice of appeal to the U.S. Court of Appeals. The appeal, which has been fully briefed, was heard on August 22, 2017, and a decision is pending. Duke Energy Florida cannot predict the outcome of this appeal.

Westinghouse Contract Litigation

On March 28, 2014, Duke Energy Florida filed a lawsuit against Westinghouse in the U.S. District Court for the Western District of North Carolina. The lawsuit seeks recovery of $54 million in milestone payments in excess of work performed under the terminated EPC for Levy as well as a determination by the court of the amounts due to Westinghouse as a result of the termination of the EPC. Duke Energy Florida recognized an exit obligation as a result of the termination of the EPC contract.

On March 31, 2014, Westinghouse filed a lawsuit against Duke Energy Florida in U.S. District Court for the Western District of Pennsylvania. The Pennsylvania lawsuit alleged damages under the EPC in excess of $510 million for engineering and design work, costs to end supplier contracts and an alleged termination fee.

On June 9, 2014, the judge in the North Carolina case ruled that the litigation will proceed in the Western District of North Carolina. On July 11, 2016, Duke Energy Florida and Westinghouse filed separate Motions for Summary Judgment. On September 29, 2016, the court issued its ruling on the parties' respective Motions for Summary Judgment, ruling in favor of Westinghouse on a $30 million termination fee claim and dismissing Duke Energy Florida's $54 million refund claim, but stating that Duke Energy Florida could use the refund claim to offset any damages for termination costs. Westinghouse's claim for termination costs was unaffected by this ruling and continued to trial. At trial, Westinghouse reduced its claim for termination costs from $482 million to $424 million. Following a trial on the matter, the court issued its final order in December 2016 denying Westinghouse's claim for termination costs and re-affirming its earlier ruling in favor of Westinghouse on the $30 million termination fee and Duke Energy Florida's refund claim. Judgment was entered against Duke Energy Florida in the amount of approximately $34 million, which includes pre-judgment interest. Westinghouse has appealed the trial court's order and Duke Energy Florida has cross-appealed. Duke Energy Florida cannot predict the ultimate outcome of the appeal of the trial court's order.

On March 29, 2017, Westinghouse filed Chapter 11 bankruptcy in the Southern District of New York, which automatically stayed the appeal. On May 23, 2017, the bankruptcy court entered an order lifting the stay with respect to the appeal. Briefing of the appeal concluded on October 20, 2017. Oral argument in the appeal was originally set for March 2018 but has tentatively been rescheduled to May 2018, due to scheduling conflicts.

Ultimate resolution of these matters could have a material effect on the results of operations, financial position or cash flows of Duke Energy Florida. See discussion of the 2017 Settlement and the Levy Nuclear Project in Note 4 for additional information regarding recovery of costs related to Westinghouse. The 2017 Settlement does not permit recovery of any amounts paid to resolve this contract litigation.

MGP Cost Recovery Action

On December 30, 2011, Duke Energy Florida filed a lawsuit against FirstEnergy Corp. (FirstEnergy) to recover investigation and remediation costs incurred by Duke Energy Florida in connection with the restoration of two former MGP sites in Florida. Duke Energy Florida alleged that FirstEnergy, as the successor to Associated Gas & Electric Co., owes past and future contribution and response costs of up to $43 million for the investigation and remediation of MGP sites. On December 6, 2016, the trial court entered judgment against Duke Energy Florida in the case. In January 2017, Duke Energy Florida appealed the decision to the U.S. Court of Appeals for the Sixth Circuit, which has been fully briefed and argued. Duke Energy Florida cannot predict the outcome of this appeal.

Duke Energy Ohio

Antitrust Lawsuit

In January 2008, four plaintiffs, including individual, industrial and nonprofit customers, filed a lawsuit against Duke Energy Ohio in federal court in the Southern District of Ohio. Plaintiffs alleged Duke Energy Ohio conspired to provide inequitable and unfair price advantages for certain large business consumers by entering into nonpublic option agreements in exchange for their withdrawal of challenges to Duke Energy Ohio's Rate Stabilization Plan implemented in early 2005. In March 2014, a federal judge certified this matter as a class action. Plaintiffs alleged claims of antitrust violations under the federal Robinson Patman Act as well as fraud and conspiracy allegations under the federal Racketeer Influenced and Corrupt Organizations statute and the Ohio Corrupt Practices Act.

During 2015, the parties received preliminary court approval of a settlement agreement. Duke Energy Ohio recorded a litigation settlement reserve of $81 million classified in Other within Current Liabilities on the Consolidated Balance Sheet at December 31, 2015. Duke Energy Ohio also recognized a pretax charge of $81 million in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2015. The settlement agreement was approved at a federal court hearing on April 19, 2016. Distribution of the settlement checks was approved by the court in January 2017 and all settlement amounts have been paid. See Note 2 for further discussion on the Midwest Generation Exit.

Other Litigation and Legal Proceedings

The Duke Energy Registrants are involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve significant amounts. The Duke Energy Registrants believe the final disposition of these proceedings will not have a material effect on their results of operations, cash flows or financial position.

The table below presents recorded reserves based on management's best estimate of probable loss for legal matters, excluding asbestos-related reserves and the exit obligation discussed above related to the termination of an EPC contract. Reserves are classified on the Consolidated Balance Sheets in Other within Other Noncurrent Liabilities and Accounts payable and Other within Current Liabilities. The reasonably possible range of loss in excess of recorded reserves is not material, other than as described above.

	December 31,	
(in millions)	**2017**	**2016**
Reserves for Legal Matters		
Duke Energy	**$ 88**	$ 98
Duke Energy Carolinas	**30**	23
Progress Energy	**55**	59
Duke Energy Progress	**13**	14
Duke Energy Florida	**24**	28
Duke Energy Ohio	**—**	4
Piedmont	**2**	2

OTHER COMMITMENTS AND CONTINGENCIES

General

As part of their normal business, the Duke Energy Registrants are party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various subsidiaries, investees and other third parties. These guarantees involve elements of performance and credit risk, which are not fully recognized on the Consolidated Balance Sheets and have unlimited maximum potential payments. However, the Duke Energy Registrants do not believe these guarantees will have a material effect on their results of operations, cash flows or financial position.

Purchase Obligations

Purchased Power

Duke Energy Progress, Duke Energy Florida and Duke Energy Ohio have ongoing purchased power contracts, including renewable energy contracts, with other utilities, wholesale marketers, co-generators and qualified facilities. These purchased power contracts generally provide for capacity and energy payments. In addition, Duke Energy Progress and Duke Energy Florida have various contracts to secure transmission rights.

The following table presents executory purchased power contracts with terms exceeding one year, excluding contracts classified as leases. Amounts at Duke Energy Ohio were immaterial.

		Minimum Purchase Amount at December 31, 2017						
(in millions)	**Contract Expiration**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Duke Energy Progress[a]	2019-2031	$ 68	$ 68	$ 51	$ 52	$ 30	$ 239	$ 508
Duke Energy Florida[b]	2021-2043	357	374	394	378	376	770	2,649

(a) Contracts represent between 15 percent and 100 percent of net plant output.
(b) Contracts represent between 81 percent and 100 percent of net plant output.

Gas Supply and Capacity Contracts

Duke Energy Ohio and Piedmont routinely enter into long-term natural gas supply commodity and capacity commitments and other agreements that commit future cash flows to acquire services needed in their businesses. These commitments include pipeline and storage capacity contracts and natural gas supply contracts to provide service to customers. Costs arising from the natural gas supply commodity and capacity commitments, while significant, are pass-through costs to customers and are generally fully recoverable through the fuel adjustment or PGA procedures and prudence reviews in North Carolina and South Carolina and under the Tennessee Incentive Plan in Tennessee. In the Midwest, these costs are recovered via the Gas Cost Recovery Rate in Ohio or the Gas Cost Adjustment Clause in Kentucky. The time periods for fixed payments under pipeline and storage capacity contracts are up to 19 years. The time periods for fixed payments under natural gas supply contracts are up to three years. The time period for the natural gas supply purchase commitments is up to 15 years.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the FERC in order to maintain rights to access the natural gas storage or pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the Consolidated Statements of Operations and Comprehensive Income as part of natural gas purchases and are included in Cost of natural gas.

The following table presents future unconditional purchase obligations under natural gas supply and capacity contracts as of December 31, 2017.

(in millions)	**Duke Energy**	**Duke Energy Ohio**	**Piedmont**
2018	**$ 314**	**$ 37**	**$ 277**
2019	**280**	**28**	**252**
2020	**252**	**25**	**227**
2021	**249**	**26**	**223**
2022	**226**	**11**	**215**
Thereafter	**1,121**	**3**	**1,118**
Total	**$ 2,442**	**$ 130**	**$ 2,312**

Operating and Capital Lease Commitments

The Duke Energy Registrants lease office buildings, railcars, vehicles, computer equipment and other property and equipment with various terms and expiration dates. Additionally, Duke Energy Progress has a capital lease related to firm natural gas pipeline transportation capacity. Duke Energy Progress and Duke Energy Florida have entered into certain purchased power agreements, which are classified as leases. Consolidated capitalized lease obligations are classified as Long-Term Debt or Other within Current Liabilities on the Consolidated Balance Sheets. Amortization of assets recorded under capital leases is included in Depreciation and amortization and Fuel used in electric generation on the Consolidated Statements of Operations.

The following tables present rental expense for operating leases. These amounts are included in Operation, maintenance and other on the Consolidated Statements of Operations.

	Years Ended December 31,

(in millions)	2017	2016	2015
Duke Energy	$ 241	$ 242	$ 313
Duke Energy Carolinas	44	45	41
Progress Energy	130	140	230
Duke Energy Progress	75	68	149
Duke Energy Florida	55	72	81
Duke Energy Ohio	15	16	13
Duke Energy Indiana	23	23	20

	Year Ended	Two Months Ended	Years Ended October 31,	
(in millions)	December 31, 2017	December 31, 2016	2016	2015
Piedmont	$ 7	$ 1	$ 5	$ 5

The following table presents future minimum lease payments under operating leases, which at inception had a non-cancelable term of more than one year.

	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2018	$ 233	$ 36	$ 133	$ 77	$ 56	$ 20	$ 22	$ 6
2019	203	29	126	72	54	12	14	5
2020	183	25	117	62	55	10	10	5
2021	150	19	97	48	49	7	8	6
2022	135	16	90	42	48	4	5	6
Thereafter	882	52	525	344	181	5	7	16
Total	$ 1,786	$ 177	$ 1,088	$ 645	$ 443	$ 58	$ 66	$ 44

The following table presents future minimum lease payments under capital leases.

	December 31, 2017						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
2018	$ 168	$ 13	$ 46	$ 21	$ 25	$ 3	$ 2
2019	169	13	45	20	25	1	1
2020	174	13	47	21	26	—	1
2021	176	8	45	22	25	—	1
2022	169	8	45	21	24	—	1
Thereafter	745	109	323	227	95	—	38
Minimum annual payments	1,601	164	551	332	220	4	44
Less: amount representing interest	(601)	(103)	(283)	(192)	(91)	—	(33)

Total	$ 1,000	$ 61	$ 268	$ 140	$ 129	$ 4	$ 11

6. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	December 31, 2017								
(in millions)	**Weighted Average Interest Rate**	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Unsecured debt, maturing 2018-2073	4.17%	$ 20,409	$ 1,150	$ 3,950	$ —	$ 550	$ 900	$ 411	$ 2,050
Secured debt, maturing 2018-2037	3.15%	4,458	450	1,757	300	1,457	—	—	—
First mortgage bonds, maturing 2018-2047[a]	4.51%	23,529	7,959	11,801	6,776	5,025	1,100	2,669	—
Capital leases, maturing 2018-2051[b]	4.55%	1,000	61	269	139	129	5	11	—
Tax-exempt bonds, maturing 2019-2041[c]	3.23%	941	243	48	48	—	77	572	—
Notes payable and commercial paper[d]	1.57%	2,788	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	404	955	390	—	54	311	364
Fair value hedge carrying value adjustment		6	6	—	—	—	—	—	—

Unamortized debt discount and premium, net[e]		**1,582**	**(19)**	**(30)**	**(16)**	**(10)**	**(33)**	**(9)**	**(1)**
Unamortized debt issuance costs[f]		**(271)**	**(47)**	**(108)**	**(40)**	**(56)**	**(7)**	**(21)**	**(12)**
Total debt	**4.09%**	**$ 54,442 $**	**10,207 $**	**18,642 $**	**7,597 $**	**7,095 $**	**2,096 $**	**3,944 $**	**2,401**
Short-term notes payable and commercial paper		**(2,163)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Short-term money pool/intercompany borrowings		**—**	**(104)**	**(805)**	**(240)**	**—**	**(29)**	**(161)**	**(364)**
Current maturities of long-term debt[g]		**(3,244)**	**(1,205)**	**(771)**	**(3)**	**(768)**	**(3)**	**(3)**	**(250)**
Total long-term debt[g]		**$ 49,035 $**	**8,898 $**	**17,066 $**	**7,354 $**	**6,327 $**	**2,064 $**	**3,780 $**	**1,787**

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $81 million and $603 million of capital lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to power purchase agreements that are not accounted for as capital leases in their respective financial statements because of grandfathering provisions in GAAP.
(c) Substantially all tax-exempt bonds are secured by first mortgage bonds or letters of credit.
(d) Includes $625 million that was classified as Long-Term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities that backstop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted average days to maturity for Duke Energy's commercial paper program was 14 days.
(e) Duke Energy includes $1,509 million and $176 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $47 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(g) Refer to Note 17 for additional information on amounts from consolidated VIEs.

	December 31, 2016								
(in millions)	**Weighted Average Interest Rate**	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Unsecured debt, maturing 2017-2073	4.30%	$ 17,812 $	1,150 $	3,551 $	— $	150 $	810 $	415 $	1,835
Secured debt, maturing 2017-2037	2.60%	3,909	425	1,819	300	1,519	—	—	—
First mortgage bonds, maturing 2017-2046[a]	4.61%	21,879	7,410	10,800	6,425	4,375	1,000	2,669	—
Capital leases, maturing 2018-2051[b]	4.48%	1,100	22	285	142	143	7	11	—
Tax-exempt bonds, maturing 2017-2041[c]	2.84%	1,053	355	48	48	—	77	572	—
Notes payable and commercial paper[d]	1.01%	3,112	—	—	—	—	—	—	—
Money pool/intercompany borrowings[e]		—	300	1,902	150	297	41	150	—
Fair value hedge carrying value adjustment		6	6	—	—	—	—	—	—
Unamortized debt discount and premium, net[f]		1,753	(20)	(31)	(16)	(10)	(28)	(9)	(1)
Unamortized debt issuance costs[g]		(242)	(45)	(104)	(38)	(52)	(7)	(22)	(13)
Total debt	4.07%	$ 50,382 $	9,603 $	18,270 $	7,011 $	6,422 $	1,900 $	3,786 $	1,821
Short-term notes payable and									

commercial paper	(2,487)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings	—	—	(729)	—	(297)	(16)	—	—
Current maturities of long-term debt(h)	(2,319)	(116)	(778)	(452)	(326)	(1)	(3)	(35)
Total long-term debt(h)	$ 45,576	$ 9,487	$ 16,763	$ 6,559	$ 5,799	$ 1,883	$ 3,783	$ 1,786

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $98 million and $670 million of capital lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to power purchase agreements that are not accounted for as capital leases in their respective financial statements because of grandfathering provisions in GAAP.
(c) Substantially all tax-exempt bonds are secured by first mortgage bonds or letters of credit.
(d) Includes $625 million that was classified as Long-Term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities that backstop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted average days to maturity for Duke Energy and Piedmont's commercial paper programs were 14 days and eight days, respectively.
(e) Progress Energy amount includes a $1 billion intercompany loan related to the sale of the International Disposal Group. See Note 2 for further discussion of the sale.
(f) Duke Energy includes $1,653 million and $197 million purchase accounting adjustments related to the mergers with Progress Energy and Piedmont, respectively.
(g) Duke Energy includes $53 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(h) Refer to Note 17 for additional information on amounts from consolidated VIEs.

Current Maturities of Long-Term Debt

The following table shows the significant components of Current maturities of Long-Term Debt on the Consolidated Balance Sheets. The Duke Energy Registrants currently anticipate satisfying these obligations with cash on hand and proceeds from additional borrowings.

(in millions)	Maturity Date	Interest Rate	December 31, 2017
Unsecured Debt			
Duke Energy (Parent)	June 2018	6.250%	$ **250**
Duke Energy (Parent)	June 2018	2.100%	**500**
Piedmont	December 2018	2.286% (b)	**250**
First Mortgage Bonds			
Duke Energy Carolinas	January 2018	5.250%	**400**
Duke Energy Carolinas	April 2018	5.100%	**300**
Duke Energy Florida	June 2018	5.650%	**500**
Duke Energy Carolinas	November 2018	7.000%	**500**
Other(a)			**544**
Current maturities of long-term debt			$ **3,244**

(a) Includes capital lease obligations, amortizing debt and small bullet maturities.
(b) Debt has a floating interest rate.

Maturities and Call Options

The following table shows the annual maturities of long-term debt for the next five years and thereafter. Amounts presented exclude short-term notes payable and commercial paper and money pool borrowings for the Subsidiary Registrants.

	December 31, 2017				
	Duke	Duke	Duke	Duke	Duke

(in millions)	Duke Energy(a)	Energy Carolinas	Progress Energy	Energy Progress	Energy Florida	Energy Ohio	Energy Indiana	Piedmont
2018	$ 3,244	$ 1,205	$ 771	$ 3	$ 768	$ 3	$ 3	$ 250
2019	3,563	6	2,191	903	490	548	61	—
2020	3,699	906	871	304	568	—	502	—
2021	3,760	502	1,472	602	371	48	69	159
2022	3,010	302	1,176	653	74	23	243	—
Thereafter	33,271	7,182	11,356	4,892	4,824	1,445	2,905	1,628
Total long-term debt, including current maturities	$ 50,547	$ 10,103	$ 17,837	$ 7,357	$ 7,095	$ 2,067	$ 3,783	$ 2,037

(a) Excludes $1,732 million in purchase accounting adjustments related to the Progress Energy merger and the Piedmont acquisition.

The Duke Energy Registrants have the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than as presented above.

Short-Term Obligations Classified as Long-Term Debt

Tax-exempt bonds that may be put to the Duke Energy Registrants at the option of the holder and certain commercial paper issuances and money pool borrowings are classified as Long-Term Debt on the Consolidated Balance Sheets. These tax-exempt bonds, commercial paper issuances and money pool borrowings, which are short-term obligations by nature, are classified as long term due to Duke Energy's intent and ability to utilize such borrowings as long-term financing. As Duke Energy's Master Credit Facility and other bilateral letter of credit agreements have non-cancelable terms in excess of one year as of the balance sheet date, Duke Energy has the ability to refinance these short-term obligations on a long-term basis. The following tables show short-term obligations classified as long-term debt.

	December 31, 2017				
(in millions)	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Ohio	Duke Energy Indiana
Tax-exempt bonds	$ 312	$ —	$ —	$ 27	$ 285
Commercial paper(a)	625	300	150	25	150
Total	$ 937	$ 300	$ 150	$ 52	$ 435

	December 31, 2016				
(in millions)	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Ohio	Duke Energy Indiana
Tax-exempt bonds	$ 347	$ 35	$ —	$ 27	$ 285
Commercial paper(a)	625	300	150	25	150
Total	$ 972	$ 335	$ 150	$ 52	$ 435

(a) Progress Energy amounts are equal to Duke Energy Progress amounts.

Summary of Significant Debt Issuances

The following tables summarize significant debt issuances (in millions).

			Year Ended December 31, 2017					
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio
Unsecured Debt								
April 2017[a]	April 2025	3.364%	$ **420**	$ **420**	$ **—**	$ **—**	$ **—**	$ **—**
June 2017[b]	June 2020	2.100%	**330**	**330**	**—**	**—**	**—**	**—**
August 2017[c]	August 2022	2.400%	**500**	**500**	**—**	**—**	**—**	**—**
August 2017[c]	August 2027	3.150%	**750**	**750**	**—**	**—**	**—**	**—**
August 2017[c]	August 2047	3.950%	**500**	**500**	**—**	**—**	**—**	**—**
December 2017[d]	December 2019 (k)	2.100%	**400**	**—**	**—**	**—**	**400**	**—**
Secured Debt								
February 2017[e]	June 2034	4.120%	**587**	**—**	**—**	**—**	**—**	**—**
August 2017[f]	December 2036	4.110%	**233**	**—**	**—**	**—**	**—**	**—**
First Mortgage Bonds								
January 2017[g]	January 2020	1.850%	**250**	**—**	**—**	**—**	**250**	**—**
January 2017[g]	January 2027	3.200%	**650**	**—**	**—**	**—**	**650**	**—**
March 2017[h]	June 2046	3.700%	**100**	**—**	**—**	**—**	**—**	**100**
September 2017[i]	September 2020	1.500% (l)	**300**	**—**	**—**	**300**	**—**	**—**
September 2017[i]	September 2047	3.600%	**500**	**—**	**—**	**500**	**—**	**—**
November 2017[j]	December 2047	3.700%	**550**	**—**	**550**	**—**	**—**	**—**
Total issuances			$ **6,070**	$ **2,500**	$ **550**	$ **800**	$ **1,300**	$ **100**

(b) Proceeds were used to refinance $400 million of unsecured debt at maturity and to repay a portion of outstanding commercial paper.
(c) Debt issued to repay a portion of outstanding commercial paper.
(d) Debt issued to repay at maturity $700 million of unsecured debt, to repay outstanding commercial paper and for general corporate purposes.

(e) Debt issued to fund storm restoration costs related to Hurricane Irma and for general corporate purposes.
(f) Portfolio financing of four Texas and Oklahoma wind facilities. Duke Energy pledged substantially all of the assets of these wind facilities and is nonrecourse to Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures.
(g) Portfolio financing of eight solar facilities located in California, Colorado and New Mexico. Duke Energy pledged substantially all of the assets of these solar facilities and is nonrecourse to Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures.
(h) Debt issued to fund capital expenditures for ongoing construction and capital maintenance, to repay a $250 million aggregate principal amount of bonds at maturity and for general corporate purposes.
(i) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance and for general corporate purposes.
(j) Debt issued to repay at maturity a $200 million aggregate principal amount of bonds at maturity, pay down intercompany short-term debt and for general corporate purposes, including capital expenditures.
(k) Debt issued to refinance $400 million aggregate principal amount of bonds due January 2018, pay down intercompany short-term debt and for general corporate purposes.
(l) Principal balance will be repaid in equal quarterly installments beginning in March 2018.
(m) Debt issuance has a floating interest rate.

			Year Ended December 31, 2016						
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Unsecured Debt									
April 2016[a]	April 2023	2.875%	$ 350	$ 350	$ —	$ —	$ —	$ —	$ —
August 2016[b]	September 2021	1.800%	750	750	—	—	—	—	—
August 2016[b]	September 2026	2.650%	1,500	1,500	—	—	—	—	—
August 2016[b]	September 2046	3.750%	1,500	1,500	—	—	—	—	—
Secured Debt									
June 2016[c]	March 2020	1.196%	183	—	—	—	183	—	—
June 2016[c]	September 2022	1.731%	150	—	—	—	150	—	—
June 2016[c]	September 2029	2.538%	436	—	—	—	436	—	—
June 2016[c]	March 2033	2.858%	250	—	—	—	250	—	—
June 2016[c]	September 2036	3.112%	275	—	—	—	275	—	—
August 2016[d]	June 2034	2.747% (i)	228	—	—	—	—	—	—
August 2016[d]	June 2020	2.747% (i)	105	—	—	—	—	—	—
First Mortgage Bonds									
March 2016[e]	March 2023	2.500%	500	—	500	—	—	—	—
March 2016[e]	March 2046	3.875%	500	—	500	—	—	—	—
May 2016[f]	May 2046	3.750%	500	—	—	—	—	—	500
June 2016[e]	June 2046	3.700%	250	—	—	—	—	250	—
September 2016[g]	October 2046	3.400%	600	—	—	—	600	—	—
September 2016[e]	October 2046	3.700%	450	—	—	450	—	—	—
November 2016[h]	December 2046	2.950%	600	—	600	—	—	—	—
Total issuances			$ 9,127	$ 4,100	$ 1,600	$ 450	$ 1,894	$ 250	$ 500

(n) Proceeds were used to pay down outstanding commercial paper and for general corporate purposes.

(o) Proceeds were used to finance a portion of the Piedmont acquisition. The $4.9 billion Bridge Facility was terminated following the issuance of this debt. See Note 2 for additional information on the Piedmont acquisition.

(p) DEFPF issued nuclear-asset recovery bonds and used the proceeds to acquire nuclear-asset recovery property from its parent, Duke Energy Florida. The nuclear-asset recovery bonds are payable only from and secured by the nuclear asset-recovery property. DEFPF is consolidated for financial reporting purposes; however, the nuclear asset-recovery bonds do not constitute a debt, liability or other legal obligation of, or interest in, Duke Energy Florida or any of its affiliates other than DEFPF. The assets of DEFPF, including the nuclear-asset recovery property, are not available to pay creditors of Duke Energy Florida or any of its affiliates. Duke Energy Florida used the proceeds from the sale to repay short-term borrowings under the intercompany money pool borrowing arrangement and make an equity distribution of $649 million to the ultimate parent, Duke Energy (Parent), which repaid short-term borrowings. The nuclear-asset recovery bonds are sequential pay amortizing bonds. The maturity date above represents the scheduled final maturity date for the bonds. See Notes 4 and 17 for additional information.

(q) Emerald State Solar, LLC, an indirect wholly owned subsidiary of Duke Energy entered into portfolio financing of approximately 22 North Carolina solar facilities. Tranche A of $228 million is secured by substantially all of the assets of the solar facilities and is nonrecourse to Duke Energy. Tranche B of $105 million is secured by an Equity Contribution Agreement with Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures related to the Emerald State Solar, LLC portfolio. The initial interest rate on the loans was six months London Interbank Offered Rate (LIBOR) plus an applicable margin of 1.75 percent plus a 0.125 percent increase every three years thereafter. In connection with this debt issuance, Emerald State Solar, LLC entered into two interest rate swaps to convert the substantial majority of the loan interest payments from variable rates to fixed rates of approximately 1.81 percent for Tranche A and 1.38 percent for Tranche B, plus the applicable margin. See Note 14 for further information on the notional amounts of the interest rate swaps.

(r) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance and for general corporate purposes.

(s) Proceeds were used to repay $325 million of unsecured debt due June 2016, $150 million of first mortgage bonds due July 2016 and for general corporate purposes.

(t) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance, to repay short-term borrowings under the intercompany money pool borrowing arrangement and for general corporate purposes.

(u) Proceeds were used to repay at maturity $350 million aggregate principal amount of certain bonds due December 2016, as well as to fund capital expenditures for ongoing construction and capital maintenance and for general corporate purposes.

(v) Debt issuance has a floating interest rate.

In July 2016, Piedmont issued $300 million unsecured notes maturing in November 2046 with an interest rate of 3.64%. Piedmont has the option to redeem all or part of the notes before May 1, 2046, at a redemption price equal to the greater of a) 100% of the principal amount of the notes to be redeemed, and b) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed, discounted to the date of redemption on a semi-annual basis at the Treasury Rate as defined in the indenture, as supplemented, plus 25 basis points and any accrued and unpaid interest to the date of redemption. Piedmont has the option to redeem all or part of the notes on or after May 1, 2046, at 100% of the principal amounts plus any accrued and unpaid interest to the date of redemption. Piedmont used the proceeds to fund capital expenditures, to repay short-term borrowings under Piedmont's commercial paper program and for general corporate purposes.

Available Credit Facilities

In March 2017, Duke Energy amended its Master Credit Facility to increase its capacity from $7.5 billion to $8 billion, and to extend the termination date of the facility from January 30, 2020, to March 16, 2022. The amendment also added Piedmont as a borrower within the Master Credit Facility. Piedmont's separate $850 million credit facility was terminated in connection with the amendment. With the amendment, the Duke Energy Registrants, excluding Progress Energy (Parent), have borrowing capacity under the Master Credit Facility up to specified sublimits for each borrower. Duke Energy has the unilateral ability at any time to increase or decrease the borrowing sublimits of each borrower, subject to a maximum sublimit for each borrower. The amount available under the Master Credit Facility has been reduced to backstop issuances of commercial paper, certain letters of credit and variable-rate demand tax-exempt bonds that may be put to the Duke Energy Registrants at the option of the holder. Duke Energy Carolinas and Duke Energy Progress are also required to each maintain $250 million of available capacity under the Master Credit Facility as security to meet obligations under plea agreements reached with the U.S. Department of Justice in 2015 related to violations at North Carolina facilities with ash basins.

In January 2018, Duke Energy further amended its Master Credit Facility with consenting lenders to extend $7.65 billion of our existing $8 billion Master Credit Facility by one year to March 16, 2023.

The table below includes the current borrowing sublimits and available capacity under these credit facilities.

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy (Parent)**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Facility size[(a)]	**$ 8,000**	**$ 2,850**	**$ 1,350**	**$ 1,250**	**$ 800**	**$ 450**	**$ 600**	**$ 700**
Reduction to backstop issuances								
Commercial paper[(b)]	**(1,799)**	**(561)**	**(371)**	**(314)**	**—**	**(45)**	**(260)**	**(248)**
Outstanding letters of credit	**(63)**	**(54)**	**(4)**	**(2)**	**(1)**	**—**	**—**	**(2)**
Tax-exempt bonds	**(81)**	**—**	**—**	**—**	**—**	**—**	**(81)**	**—**
Coal ash set-aside	**(500)**	**—**	**(250)**	**(250)**	**—**	**—**	**—**	**—**
Available capacity	**$ 5,557**	**$ 2,235**	**$ 725**	**$ 684**	**$ 799**	**$ 405**	**$ 259**	**$ 450**

(a) Represents the sublimit of each borrower.

(b) Duke Energy issued $625 million of commercial paper and loaned the proceeds through the money pool to Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio and Duke Energy Indiana. The balances are classified as Long-Term Debt Payable to Affiliated Companies in the Consolidated Balance Sheets.

Three-Year Revolving Credit Facility

In June 2017, Duke Energy (Parent) entered into a three-year $1.0 billion revolving credit facility (the Three Year Revolver). Borrowings under this facility will be used for general corporate purposes.

As of December 31, 2017, $500 million has been drawn under the Three Year Revolver. This balance is classified as Long-Term Debt on Duke Energy's Consolidated Balance Sheets. Any undrawn commitments can be drawn, and borrowings can be prepaid, at any time throughout the term of the facility. The terms and conditions of the Three Year Revolver are generally consistent with those governing Duke Energy's Master Credit Facility.

Piedmont Term Loan Facility

In June 2017, Piedmont entered into an 18-month term loan facility with commitments totaling $250 million (the Piedmont Term Loan). Borrowings under the facility will be used for general corporate purposes.

As of December 31, 2017, the entire $250 million has been drawn under the Piedmont Term Loan. This balance is classified as Long-Term Debt on Piedmont's Consolidated Balance Sheets. The terms and conditions of the Piedmont Term Loan are generally consistent with those governing Duke Energy's Master Credit Facility.

Other Debt Matters

In September 2016, Duke Energy filed a Registration statement (Form S-3) with the SEC. Under this Form S-3, which is uncapped, the Duke Energy Registrants, excluding Progress Energy, may issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings. The registration statement was filed to replace a similar prior filing upon expiration of its three-year term and also allows for the issuance of common stock by Duke Energy.

Duke Energy has an effective Form S-3 with the SEC to sell up to $3 billion of variable denomination floating-rate demand notes, called PremierNotes. The Form S-3 states that no more than $1.5 billion of the notes will be outstanding at any particular time. The notes are offered on a continuous basis and bear interest at a floating rate per annum determined by the Duke Energy PremierNotes Committee, or its designee, on a weekly basis. The interest rate payable on notes held by an investor may vary based on the principal amount of the investment. The notes have no stated maturity date, are non-transferable and may be redeemed in whole or in part by Duke Energy or at the investor’s option at any time. The balance as of December 31, 2017, and 2016 was $986 million and $1,090 million, respectively. The notes are short-term debt obligations of Duke Energy and are reflected as Notes payable and commercial paper on Duke Energy’s Consolidated Balance Sheets.

In January 2017, Duke Energy amended its Form S-3 to add Piedmont as a registrant and included in the amendment a prospectus for Piedmont under which it may issue debt securities in the same manner as other Duke Energy Registrants.

Duke Energy guaranteed debt issued by Duke Energy Carolinas of $650 million and $762 million, respectively, as of December 31, 2017, and 2016.

Money Pool

The Subsidiary Registrants, excluding Progress Energy, are eligible to receive support for their short-term borrowing needs through participation with Duke Energy and certain of its subsidiaries in a money pool arrangement. Under this arrangement, those companies with short-term funds may provide short-term loans to affiliates participating in this arrangement. The money pool is structured such that the Subsidiary Registrants, excluding Progress Energy, separately manage their cash needs and working capital requirements. Accordingly, there is no net settlement of receivables and payables between money pool participants. Duke Energy (Parent), may loan funds to its participating subsidiaries, but may not borrow funds through the money pool. Accordingly, as the money pool activity is between Duke Energy and its wholly owned subsidiaries, all money pool balances are eliminated within Duke Energy’s Consolidated Balance Sheets.

Money pool receivable balances are reflected within Notes receivable from affiliated companies on the Subsidiary Registrants’ Consolidated Balance Sheets. Money pool payable balances are reflected within either Notes payable to affiliated companies or Long-Term Debt Payable to Affiliated Companies on the Subsidiary Registrants’ Consolidated Balance Sheets.

Restrictive Debt Covenants

The Duke Energy Registrants’ debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65 percent for each borrower, excluding Piedmont, and 70 percent for Piedmont. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2017, each of the Duke Energy Registrants was in compliance with all covenants related to their debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Other Loans

As of December 31, 2017, and 2016, Duke Energy had loans outstanding of $701 million, including $38 million at Duke Energy Progress and $661 million, including $39 million at Duke Energy Progress, respectively, against the cash surrender value of life insurance policies it owns on the lives of its executives. The amounts outstanding were carried as a reduction of the related cash surrender value that is included in Other within Investments and Other Assets on the Consolidated Balance Sheets.

7. GUARANTEES AND INDEMNIFICATIONS

Duke Energy and Progress Energy have various financial and performance guarantees and indemnifications, which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy and Progress Energy enter into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. At December 31, 2017, Duke Energy and Progress Energy do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included on the accompanying Consolidated Balance Sheets.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses to shareholders. Guarantees issued by Duke Energy or its affiliates, or assigned to Duke Energy prior to the spin-off, remained with Duke Energy subsequent to the spin-off. Guarantees issued by Spectra Energy Capital, LLC (Spectra Capital) or its affiliates prior to the spin-off remained with Spectra Capital subsequent to the spin-off, except for guarantees that were later assigned to Duke Energy. Duke Energy has indemnified Spectra Capital against any losses incurred under certain of the guarantee obligations that remain with Spectra Capital. At December 31, 2017, the maximum potential amount of future payments associated with these guarantees was $205 million, the majority of which expires by 2028.

Duke Energy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities, as well as guarantees of debt of certain non-consolidated entities and less than wholly owned consolidated entities. If such entities were to default on payments or performance, Duke Energy would be required under the guarantees to make payments on the obligations of the less than wholly owned entity. The maximum potential amount of future payments required under these guarantees as of December 31, 2017, was $326 million. Of this amount, $11 million relates to guarantees issued on behalf of less than wholly owned consolidated entities, with the remainder related to guarantees issued on behalf of third parties and unconsolidated affiliates of Duke Energy. Of the guarantees noted above, $281 million of the guarantees expire between 2019 and 2030, with the remaining performance guarantees having no contractual expiration.

In October 2017, ACP executed a $3.4 billion revolving credit facility with a stated maturity date of October 2021. Duke Energy entered into a guarantee agreement to support its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is limited to 47 percent of the outstanding borrowings under the credit facility, which was $312 million as of December 31, 2017.

Duke Energy has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a wholly owned and former non-wholly owned entity to honor its obligations to a third party. Under these arrangements, Duke Energy has payment obligations that are triggered by a draw by the third party or customer due to the failure of the wholly owned or former non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2017, Duke Energy had guaranteed $81 million of outstanding surety bonds, most of which have no set expiration.

Duke Energy uses bank-issued stand-by letters of credit to secure the performance of wholly owned and non-wholly owned entities to a third party or customer. Under these arrangements, Duke Energy has payment obligations to the issuing bank that are triggered by a draw by the third party or customer due to the failure of the wholly owned or non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2017, Duke Energy had issued a total of $449 million in letters of credit, which expire between 2018 and 2022. The unused amount under these letters of credit was $66 million.

Duke Energy and Progress Energy have issued indemnifications for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2017, the estimated maximum exposure for these indemnifications was $89 million, most of which have no set expiration. For certain matters for which Progress Energy receives timely notice, indemnity obligations may extend beyond the notice period. Certain indemnifications related to discontinued operations have no limitations as to time or maximum potential future payments.

Duke Energy recognized $21 million and $13 million, as of December 31, 2017, and 2016, respectively, primarily in Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets, for the guarantees discussed above. As current estimates change, additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded by the Duke Energy Registrants in the future.

8. JOINT OWNERSHIP OF GENERATING AND TRANSMISSION FACILITIES

The Duke Energy Registrants maintain ownership interests in certain jointly owned generating and transmission facilities. The Duke Energy Registrants are entitled to a share of the generating capacity and output of each unit equal to their respective ownership interests. The Duke Energy Registrants pay their ownership share of additional construction costs, fuel inventory purchases and operating expenses. The Duke Energy Registrants share of revenues and operating costs of the jointly owned facilities is included within the corresponding line in the Consolidated Statements of Operations. Each participant in the jointly owned facilities must provide its own financing.

The following table presents the Duke Energy Registrants' interest of jointly owned plant or facilities and amounts included on the Consolidated Balance Sheets. All facilities are operated by the Duke Energy Registrants and are included in the Electric Utilities and Infrastructure segment.

	December 31, 2017			
(in millions except for ownership interest)	**Ownership Interest**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction Work in Progress**

Duke Energy Carolinas				
Catawba Nuclear Station (units 1 and 2)[a]	19.25%	$ 927	$ 651	$ 19
Lee Combined Combustion Station[b]	86.67%	—	—	552
Duke Energy Ohio				
Transmission facilities[c]	Various	89	63	1
Duke Energy Indiana				
Gibson Station (unit 5)[d]	50.05%	348	162	9
Vermillion Generating Station[e]	62.5%	155	120	—
Transmission and local facilities[d]	Various	4,672	1,739	—

(a) Jointly owned with North Carolina Municipal Power Agency Number 1, NCEMC and Piedmont Municipal Power Agency.
(b) Jointly owned with NCEMC.
(c) Jointly owned with America Electric Power Generation Resources and The Dayton Power and Light Company.
(d) Jointly owned with Wabash Valley Power Association, Inc. (WVPA) and Indiana Municipal Power Agency.
(e) Jointly owned with WVPA.

9. ASSET RETIREMENT OBLIGATIONS

Duke Energy records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. Certain assets of the Duke Energy Registrants' have an indeterminate life, such as transmission and distribution facilities, and thus the fair value of the retirement obligation is not reasonably estimable. A liability for these AROs will be recorded when a fair value is determinable.

The Duke Energy Registrants' regulated operations accrue costs of removal for property that does not have an associated legal retirement obligation based on regulatory orders from state commissions. These costs of removal are recorded as a regulatory liability in accordance with regulatory accounting treatment. The Duke Energy Registrants do not accrue the estimated cost of removal for any nonregulated assets. See Note 4 for the estimated cost of removal for assets without an associated legal retirement obligation, which are included in Regulatory liabilities on the Consolidated Balance Sheets.

The following table presents the AROs recorded on the Consolidated Balance Sheets.

	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Decommissioning of nuclear power facilities[a]	$ 5,371	$ 1,944	$ 3,246	$ 2,564	$ 681	$ —	$ —	$ —
Closure of ash impoundments	4,525	1,629	2,094	2,075	19	39	763	—
Other[b]	279	37	74	34	42	45	18	15
Total asset retirement obligation	$ 10,175	$ 3,610	$ 5,414	$ 4,673	$ 742	$ 84	$ 781	$ 15
Less: current portion	689	337	295	295	—	3	54	—
Total noncurrent asset retirement obligation	$ 9,486	$ 3,273	$ 5,119	$ 4,378	$ 742	$ 81	$ 727	$ 15

(a) Duke Energy amount includes purchase accounting adjustments related to the merger with Progress Energy.
(b) Primarily includes obligations related to asbestos removal. Duke Energy Ohio and Piedmont also include AROs related to the retirement of natural gas mains and services. Duke Energy includes AROs related to the removal of renewable energy generation assets.

Nuclear Decommissioning Liability

AROs related to nuclear decommissioning are based on site-specific cost studies. The NCUC, PSCSC and FPSC require updated cost estimates for decommissioning nuclear plants every five years.

The following table summarizes information about the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs in the table below are stated in 2013 or 2014 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination.

(in millions)	Annual Funding Requirement[(a)]	Decommissioning Costs[(a)(b)]	Year of Cost Study
Duke Energy	$ 14	$ 8,150	2013 and 2014
Duke Energy Carolinas	—	3,420	2013
Duke Energy Progress	14	3,550	2014
Duke Energy Florida	—	1,180	2013

(a) Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida.
(b) Amounts include the Subsidiary Registrant's ownership interest in jointly owned reactors. Other joint owners are responsible for decommissioning costs related to their interest in the reactors.

Nuclear Decommissioning Trust Funds

Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida each maintain NDTFs that are intended to pay for the decommissioning costs of their respective nuclear power plants. The NDTF investments are managed and invested in accordance with applicable requirements of various regulatory bodies including the NRC, FERC, NCUC, PSCSC, FPSC and the Internal Revenue Service (IRS).

Use of the NDTF investments is restricted to nuclear decommissioning activities including license termination, spent fuel and site restoration. The license termination and spent fuel obligations relate to contaminated decommissioning and are recorded as AROs. The site restoration obligation relates to non-contaminated decommissioning and is recorded to cost of removal within Regulatory liabilities on the Consolidated Balance Sheets.

The following table presents the fair value of NDTF assets legally restricted for purposes of settling AROs associated with nuclear decommissioning. Duke Energy Florida is actively decommissioning Crystal River Unit 3 and was granted an exemption from the NRC which allows for use of the NDTF for all aspects of nuclear decommissioning. The entire balance of Duke Energy Florida's NDTF may be applied toward license termination, spent fuel and site restoration costs incurred to decommission Crystal River Unit 3. See Note 16 for additional information related to the fair value of the Duke Energy Registrants' NDTFs.

	December 31,	
(in millions)	2017	2016
Duke Energy	$ 5,864	$ 5,099
Duke Energy Carolinas	3,321	2,882
Duke Energy Progress	2,543	2,217

Nuclear Operating Licenses

Operating licenses for nuclear units are potentially subject to extension. The following table includes the current expiration of nuclear operating licenses.

Unit	Year of Expiration
Duke Energy Carolinas	
Catawba Units 1 and 2	2043
McGuire Unit 1	2041
McGuire Unit 2	2043
Oconee Units 1 and 2	2033
Oconee Unit 3	2034
Duke Energy Progress	
Brunswick Unit 1	2036
Brunswick Unit 2	2034
Harris	2046

Robinson	2030

Duke Energy Florida has requested the NRC terminate the operating license for Crystal River Unit 3 as it permanently ceased operation in February 2013. In January 2018, Crystal River Unit 3 reached a SAFSTOR status.

Closure of Ash Impoundments

The Duke Energy Registrants are subject to state and federal regulations covering the closure of coal ash impoundments, including the EPA CCR rule and the Coal Ash Act, and other agreements. AROs recorded on the Duke Energy Registrants' Consolidated Balance Sheets include the legal obligation for closure of coal ash basins and the disposal of related ash as a result of these regulations and agreements.

The Coal Ash Act, as amended, requires excavation of the Sutton, Riverbend and Dan River basins by August 1, 2019, and Asheville basins by August 1, 2022. Excavation at these sites may include a combination of transfer of coal ash to an engineered landfill or conversion for beneficial use. Basins at the H.F. Lee, Cape Fear and Weatherspoon sites are required to be closed through excavation no later than August 1, 2028. Excavation at these sites can include conversion of the basin to a lined industrial landfill, transfer of ash to an engineered landfill or conversion for beneficial use. The remaining basins are required to be closed no later than December 31, 2024, through conversion to a lined industrial landfill, transfer to an engineered landfill or conversion for beneficial use, unless certain dam improvement projects and alternative drinking water source projects are completed by October 15, 2018. Upon satisfactory completion of these projects, the closure deadline would be extended to December 31, 2029, and could include closure through the combination of a cap system and a groundwater monitoring system.

The Coal Ash Act also required the installation and operation of three large-scale coal ash beneficiation projects to produce reprocessed ash for use in the concrete industry. Duke Energy selected the Buck, H.F. Lee and Cape Fear plants for these projects. Closure at these sites is required to be completed no later than December 31, 2029.

The Coal Ash Act includes a variance procedure for compliance deadlines and other issues surrounding the management of CCR and CCR surface impoundments and prohibits cost recovery in customer rates for unlawful discharge of ash impoundment waters occurring after January 1, 2014. The Coal Ash Act leaves the decision on cost recovery determinations related to closure of ash impoundments to the normal ratemaking processes before utility regulatory commissions. Closure plans and all associated permits must be approved by NCDEQ before any closure work can begin.

The EPA CCR rule establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. The EPA CCR rule has certain requirements which if not met could initiate impoundment closure and require closure completion within five years. The EPA CCR rule includes extension requirements, which if met could allow the extension of closure completion by up to 10 years.

The ARO amount recorded on the Consolidated Balance Sheets is based upon estimated closure costs for impacted ash impoundments. The amount recorded represents the discounted cash flows for estimated closure costs based upon either specific closure plans or the probability weightings of the potential closure methods as evaluated on a site-by-site basis. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from ash basins, consolidating material as necessary and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill or recycling the ash for concrete or some other beneficial use. The ultimate method and timetable for closure will be in compliance with standards set by federal and state regulations and other agreements. The ARO amount will be adjusted as additional information is gained through the closure and post-closure process, including acceptance and approval of compliance approaches which may change management assumptions, and may result in a material change to the balance. See ARO Liability Rollforward section below for information on revisions made to the coal ash liability during 2017 and 2016.

Asset retirement costs associated with the AROs for operating plants and retired plants are included in Net property, plant and equipment and Regulatory assets, respectively, on the Consolidated Balance Sheets. See Note 4 for additional information on Regulatory assets related to AROs.

Cost recovery for future expenditures will be pursued through the normal ratemaking process with federal and state utility commissions, which permit recovery of necessary and prudently incurred costs associated with Duke Energy’s regulated operations. See Note 4 for additional information on recovery of coal ash costs.

ARO Liability Rollforward

During 2017 and 2016, the Duke Energy Registrants updated coal ash ARO liability estimates based on additional site-specific information for the related costs, methods and timing of work to be performed. Actual closure costs incurred could be materially different from current estimates that form the basis of the recorded AROs.

The following tables present changes in the liability associated with AROs.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Balance at December 31, 2015	$ 10,249	$ 3,918	$ 5,369	$ 4,567	$ 802	$ 125	$ 525
Acquisitions[a]	22	—	2	—	2	—	—
Accretion expense[b]	400	187	230	194	35	5	24
Liabilities settled[c]	(613)	(287)	(272)	(212)	(60)	(5)	(49)
Liabilities incurred in the current year	51	—	3	3	—	—	29
Revisions in estimates of cash flows	502	77	143	145	(1)	(48)	337
Balance at December 31, 2016	10,611	3,895	5,475	4,697	778	77	866
Accretion expense[b]	**435**	**184**	**228**	**195**	**33**	**3**	**32**
Liabilities settled[c]	**(619)**	**(282)**	**(270)**	**(204)**	**(65)**	**(7)**	**(49)**
Liabilities incurred in the current year[d]	**51**	**5**	**—**	**—**	**—**	**7**	**29**
Revisions in estimates of cash flows	**(303)**	**(192)**	**(19)**	**(15)**	**(4)**	**4**	**(97)**
Balance at December 31, 2017	**$ 10,175**	**$ 3,610**	**$ 5,414**	**$ 4,673**	**$ 742**	**$ 84**	**$ 781**

(a) Duke Energy amount relates to the Piedmont acquisition. See Note 2 for additional information.
(b) Substantially all accretion expense for the years ended December 31, 2017, and 2016 relates to Duke Energy's regulated electric operations and has been deferred in accordance with regulatory accounting treatment.
(c) Amounts primarily relate to ash impoundment closures and nuclear decommissioning of Crystal River Unit 3.
(d) Amounts primarily relate to AROs recorded as a result of state agency closure requirements at Duke Energy Indiana.

(in millions)		Piedmont
Balance at October 31, 2015	$	20
Accretion expense		1
Liabilities settled		(7)
Liabilities incurred in the current year		6
Revisions in estimates of cash flows		(6)
Balance at October 31, 2016		14
Liabilities settled		(1)
Liabilities incurred in the current year		1
Balance at December 31, 2016		14
Accretion expense		**1**
Liabilities settled		**(8)**
Liabilities incurred in the current year		**8**
Balance at December 31, 2017	**$**	**15**

10. PROPERTY, PLANT AND EQUIPMENT

The following tables summarize the property, plant and equipment for Duke Energy and its subsidiary registrants.

	December 31, 2017								
(in millions)	Estimated Useful Life (Years)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Land		$ 1,559	$ 467	$ 767	$ 424	$ 343	$ 134	$ 111	$ 41
Plant – Regulated									
Electric generation, distribution and transmission	8-100	93,687	35,657	39,419	24,502	14,917	4,870	13,741	—
Natural gas transmission and distribution	12-80	8,292	—	—	—	—	2,559	—	5,733
Other buildings and improvements	15-100	1,936	647	652	316	336	243	240	154
Plant – Nonregulated									
Electric generation, distribution and transmission[a]	5-30	4,273	—	—	—	—	—	—	—
Other buildings and improvements	25-35	465	—	—	—	—	—	—	—
Nuclear fuel		3,680	2,120	1,560	1,560	—	—	—	—
Equipment	3-55	2,122	402	555	416	139	348	169	266
Construction in process		6,995	2,614	3,059	1,434	1,625	350	416	231
Other	3-40	4,498	1,032	1,311	931	370	228	271	300
Total property, plant and equipment[b][e]		127,507	42,939	47,323	29,583	17,730	8,732	14,948	6,725
Total accumulated depreciation – regulated[c][d][e]		(39,742)	(15,063)	(15,857)	(10,903)	(4,947)	(2,691)	(4,662)	(1,479)
Total accumulated depreciation – nonregulated[d][e]		(1,795)	—	—	—	—	—	—	—
Generation facilities to be retired, net		421	—	421	421	—	—	—	—
Total net property, plant and equipment		$ 86,391	$ 27,876	$ 31,887	$ 19,101	$ 12,783	$ 6,041	$ 10,286	$ 5,246

(a) Includes a pretax impairment charge of $58 million on a wholly owned non-contracted wind project. See discussion below.

(b) Includes capitalized leases of $1,294 million, $81 million, $272 million, $139 million, $133 million, $80 million and $35 million at Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana, respectively, primarily within Plant – Regulated. The Progress Energy, Duke Energy Progress and Duke Energy Florida amounts are net of $114 million, $11 million and $103 million, respectively, of accumulated amortization of capitalized leases.

(c) Includes $2,113 million, $1,283 million, $831 million and $831 million of accumulated amortization of nuclear fuel at Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.

(d) Includes accumulated amortization of capitalized leases of $57 million, $11 million, $21 million and $9 million at Duke Energy, Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana, respectively.

(e) Includes gross property, plant and equipment cost of consolidated VIEs of $3,941 million and accumulated depreciation of consolidated VIEs of $598 million at Duke Energy.

	December 31, 2016								
(in millions)	Estimated Useful Life (Years)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Land		$ 1,501	$ 432	$ 735	$ 393	$ 342	$ 150	$ 106	$ 39
Plant – Regulated									
Electric generation, distribution and transmission	8-100	89,864	34,515	37,596	23,683	13,913	4,593	13,160	—
Natural gas transmission and distribution	12-67	7,738	—	—	—	—	2,456	—	5,282
Other buildings and improvements	15-100	1,692	502	634	293	341	211	197	148
Plant – Nonregulated									
Electric generation, distribution and transmission	5-30	4,298	—	—	—	—	—	—	—
Other buildings and improvements	25-35	421	—	—	—	—	—	—	—
Nuclear fuel		3,572	2,092	1,480	1,480	—	—	—	—
Equipment	3-38	1,941	358	505	378	127	338	156	260
Construction in process		6,186	2,324	2,708	1,329	1,379	206	396	210
Other	5-40	4,184	904	1,206	863	332	172	226	235
Total property, plant and equipment(a)(d)		121,397	41,127	44,864	28,419	16,434	8,126	14,241	6,174
Total accumulated depreciation – regulated(b)(c)(d)		(37,831)	(14,365)	(15,212)	(10,561)	(4,644)	(2,579)	(4,317)	(1,360)
Total accumulated depreciation – nonregulated(c)(d)		(1,575)	—	—	—	—	—	—	—
Generation facilities to be retired, net		529	—	529	529	—	—	—	—
Total net property, plant and equipment		$ 82,520	$ 26,762	$ 30,181	$ 18,387	$ 11,790	$ 5,547	$ 9,924	$ 4,814

(a) Includes capitalized leases of $1,355 million, $40 million, $288 million, $142 million, $146 million, $81 million and $35 million at Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana, respectively, primarily within Plant – Regulated. The Progress Energy, Duke Energy Progress and Duke Energy Florida amounts are net of $99 million, $9 million and $90 million, respectively, of accumulated amortization of capitalized leases.

(b) Includes $1,922 million, $1,192 million, $730 million and $730 million of accumulated amortization of nuclear fuel at Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.
(c) Includes accumulated amortization of capitalized leases of $50 million, $9 million, $19 million and $8 million at Duke Energy, Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana, respectively.
(d) Includes gross property, plant and equipment cost of consolidated VIEs of $2,591 million and accumulated depreciation of consolidated VIEs of $411 million at Duke Energy.

During the year ended December 31, 2017, Duke Energy recorded a pretax impairment charge of $69 million on a wholly owned non-contracted wind project. The impairment was recorded within Impairment charges on Duke Energy's Consolidated Statements of Operations. $58 million of the impairment related to property, plant and equipment and $11 million of the impairment related to a net intangible asset; see Note 11 for additional information. The charge represents the excess carrying value over the estimated fair value of the project, which was based on a Level 3 Fair Value measurement that was determined from the income approach using discounted cash flows. The impairment was primarily due to the non-contracted wind project being located in a market that has experienced continued declining market pricing during 2017 and declining long-term forecasted energy and capacity prices, driven by low natural gas prices, additional renewable generation placed in service and lack of significant load growth.

The following tables present capitalized interest, which includes the debt component of AFUDC.

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Duke Energy	**$ 128**	$ 100	$ 98
Duke Energy Carolinas	**45**	38	38
Progress Energy	**45**	31	24
Duke Energy Progress	**21**	17	20
Duke Energy Florida	**24**	14	4
Duke Energy Ohio	**10**	8	10
Duke Energy Indiana	**9**	7	6

	Year Ended	Two Months Ended	Years Ended October 31,	
(in millions)	**December 31, 2017**	**December 31, 2016**	**2016**	**2015**
Piedmont	**$ 12**	$ 2	$ 12	$ 11

Operating Leases

Duke Energy's Commercial Renewables segment operates various renewable energy projects and sells the generated output to utilities, electric cooperatives, municipalities and commercial and industrial customers through long-term contracts. In certain situations, these long-term contracts and the associated renewable energy projects qualify as operating leases. Rental income from these leases is accounted for as Operating Revenues in the Consolidated Statements of Operations. There are no minimum lease payments as all payments are contingent based on actual electricity generated by the renewable energy projects. Contingent lease payments were $262 million, $216 million, and $172 million for the years ended December 31, 2017, 2016 and 2015. As of December 31, 2017, renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,153 million and accumulated depreciation of $459 million. These assets are principally classified as nonregulated electric generation and transmission assets.

11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

Duke Energy

The following table presents goodwill by reportable operating segment for Duke Energy included on Duke Energy's Consolidated Balance Sheets at December 31, 2017, and 2016.

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
Goodwill Balance at December 31, 2016	$ 17,379	$ 1,924	$ 122	$ 19,425
Accumulated impairment charges[a]	**—**	**—**	**(29)**	**(29)**
Goodwill at December 31, 2017	**$ 17,379**	**$ 1,924**	**$ 93**	**$ 19,396**

(a) Duke Energy evaluated the recoverability of goodwill during 2017 and recorded impairment charges of $29 million related to the Energy Management Solutions reporting unit within the Commercial Renewables segment. The fair value of the reporting unit was determined based on the market approach.

Duke Energy Ohio

Duke Energy Ohio's Goodwill balance of $920 million, allocated $596 million to Electric Utilities and Infrastructure and $324 million to Gas Utilities and Infrastructure, is presented net of accumulated impairment charges of $216 million on the Consolidated Balance Sheets at December 31, 2017, and 2016.

Progress Energy

Progress Energy's Goodwill is included in the Electric Utilities and Infrastructure operating segment and there are no accumulated impairment charges.

Piedmont

Piedmont's Goodwill is included in the Gas Utilities and Infrastructure operating segment and there are no accumulated impairment charges. Effective with Piedmont's fiscal year being changed to December 31, as discussed in Note 1, Piedmont changed the date of its annual impairment testing of goodwill from October 31 to August 31 to align with the other Duke Energy Registrants.

Impairment Testing

Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont are required to perform an annual goodwill impairment test as of the same date each year and, accordingly, perform their annual impairment testing of goodwill as of August 31. Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont update their test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. Except for the Energy Management Solutions reporting unit, the fair value of all other reporting units for Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont exceeded their respective carrying values at the date of the annual impairment analysis.

Intangible Assets

The following tables show the carrying amount and accumulated amortization of intangible assets included in Other within Other Noncurrent Assets on the Consolidated Balance Sheets of the Duke Energy Registrants at December 31, 2017 and 2016.

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Emission allowances	**$ 19**	**$ 1**	**$ 5**	**$ 2**	**$ 3**	**$ —**	**$ 13**	**$ —**
Renewable energy certificates	**148**	**38**	**107**	**107**	**—**	**3**	**—**	**—**
Natural gas, coal and power contracts	**24**	**—**	**—**	**—**	**—**	**—**	**24**	**—**
Renewable operating and development projects	**79**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other	**6**	**—**	**—**	**—**	**—**	**—**	**—**	**3**
Total gross carrying amounts	**276**	**39**	**112**	**109**	**3**	**3**	**37**	**3**
Accumulated amortization – natural gas, coal and power contracts	**(19)**	**—**	**—**	**—**	**—**	**—**	**(19)**	**—**
Accumulated amortization – renewable operating and development projects	**(22)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Accumulated amortization – other	**(5)**	**—**	**—**	**—**	**—**	**—**	**—**	**(3)**
Total accumulated amortization	**(46)**	**—**	**—**	**—**	**—**	**—**	**(19)**	**(3)**
Total intangible assets, net	**$ 230**	**$ 39**	**$ 112**	**$ 109**	**$ 3**	**$ 3**	**$ 18**	**$ —**

	December 31, 2016							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Emission allowances	$ 19	$ 1	$ 6	$ 2	$ 4	$ —	$ 13	$ —
Renewable energy certificates	125	36	84	84	—	4	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	97	—	—	—	—	—	—	—
Other	6	—	—	—	—	—	—	3
Total gross carrying amounts	271	37	90	86	4	4	37	3
Accumulated amortization – natural gas, coal and power contracts	(17)	—	—	—	—	—	(17)	—
Accumulated amortization – renewable operating and development projects	(23)	—	—	—	—	—	—	—
Accumulated amortization – other	(5)	—	—	—	—	—	—	(3)
Total accumulated amortization	(45)	—	—	—	—	—	(17)	(3)
Total intangible assets, net	$ 226	$ 37	$ 90	$ 86	$ 4	$ 4	$ 20	$ —

During the year ended December 31, 2017, Duke Energy recorded a pretax impairment charge of $69 million on a wholly owned non-contracted wind project. The impairment was recorded within Impairment charges on Duke Energy's Consolidated Statements of Operations. $58 million of the impairment related to property, plant and equipment and $11 million of the impairment related to a net intangible asset that was recorded in 2007 when the project was acquired. Prior to the impairment, the gross amount of the intangible asset was $18 million and the accumulated amortization was $7 million. The intangible asset was fully impaired. See Note 10 for additional information.

Amortization Expense

The following table presents amortization expense for natural gas, coal and power contracts, renewable operating projects and other intangible assets.

	December 31,		
(in millions)	2017	2016	2015
Duke Energy	**$ 7**	$ 6	$ 5
Duke Energy Indiana	**1**	1	1

The table below shows the expected amortization expense for the next five years for intangible assets as of December 31, 2017. The expected amortization expense includes estimates of emission allowances consumption and estimates of consumption of commodities such as natural gas and coal under existing contracts, as well as estimated amortization related to renewable operating projects. The amortization amounts discussed below are estimates and actual amounts may differ from these estimates due to such factors as changes in consumption patterns, sales or impairments of emission allowances or other intangible assets, delays in the in-service dates of renewable assets, additional intangible acquisitions and other events.

(in millions)	2018	2019	2020	2021	2022
Duke Energy	$ 3	$ 2	$ 2	$ 2	$ 2
Duke Energy Indiana	1	—	—	—	—

12. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

EQUITY METHOD INVESTMENTS

Investments in domestic and international affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method.

The following table presents Duke Energy's investments in unconsolidated affiliates accounted for under the equity method, as well as the respective equity in earnings, by segment.

	Years Ended December 31,				
	2017		2016		2015
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Equity in earnings
Electric Utilities and Infrastructure	**$ 89**	**$ 5**	$ 93	$ 5	$ (2)
Gas Utilities and Infrastructure	**763**	**62**	566	19	1
Commercial Renewables	**190**	**(5)**	185	(82)	(6)
Other	**133**	**57**	81	43	76
Total	**$ 1,175**	**$ 119**	$ 925	$ (15)	$ 69

During the years ended December 31, 2017, 2016 and 2015, Duke Energy received distributions from equity investments of $13 million, $31 million and $104 million, respectively, which are included in Other assets within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows. During the year ended December 31, 2017, Duke Energy received distributions from equity investments of $281 million, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

During the year ended December 31, 2017, the two months ended December 31, 2016, and the years ended October 31, 2016, and 2015, Piedmont received distributions from equity investments of $4 million, $1 million, $26 million and $25 million, respectively, which are included in Other assets within Cash Flows from Operating Activities and $2 million, $1 million, $18 million and $2 million, respectively, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

Significant investments in affiliates accounted for under the equity method are discussed below.

Electric Utilities and Infrastructure

Duke Energy owns a 50 percent interest in Duke-American Transmission Co. (DATC) and in Pioneer Transmission, LLC (Pioneer), which build, own and operate electric transmission facilities in North America.

Gas Utilities and Infrastructure

The table below outlines Duke Energy's ownership interests in natural gas pipeline companies and natural gas storage facilities.

		Investment Amount (in millions)	
Entity Name	**Ownership Interest**	**December 31, 2017**	**December 31, 2016**
Pipeline Investments			
Atlantic Coast Pipeline, LLC[(a)]	47%	**$ 397**	$ 265
Sabal Trail Transmission, LLC	7.5%	**219**	140
Constitution Pipeline, LLC[(a)]	24%	**81**	82
Cardinal Pipeline Company, LLC[(b)]	21.49%	**11**	16
Storage Facilities			
Pine Needle LNG Company, LLC[(b)]	45%	**13**	16
Hardy Storage Company, LLC[(b)]	50%	**42**	47
Total Investments[(c)]		**$ 763**	**$ 566**

(a) During the year ended December 31, 2017, Piedmont transferred its share of ownership interest in ACP and Constitution to a wholly owned subsidiary of Duke Energy at book value.
(b) Piedmont owns the Cardinal, Pine Needle and Hardy Storage investments.
(c) Duke Energy includes purchase accounting adjustments related to Piedmont.

In October 2017, Duke Energy entered into a guarantee agreement to support its share of the ACP revolving credit facility. See Note 7 for additional information. As a result of the financing, ACP returned capital of $265 million to Duke Energy.

Piedmont sold its 15 percent membership interest in SouthStar on October 3, 2016, for $160 million resulting in an after tax gain of $81 million during the year ended October 31, 2016. Piedmont's Equity in Earnings in SouthStar was $19 million for the years ended October 31, 2016, and 2015.

For regulatory matters and other information on the ACP, Sabal Trail and Constitution investments, see Notes 4 and 17.

Commercial Renewables

In 2016, Duke Energy sold its interest in three of the Catamount Sweetwater, LLC wind farm projects. Duke Energy has a 47 percent ownership interest in each of the two other Catamount Sweetwater, LLC wind farm projects and 50 percent interest in DS Cornerstone, LLC, which owns wind farm projects in the U.S.

Impairment of Equity Method Investments

Duke Energy evaluated its investment in Constitution for OTTI as of December 31, 2017. Our impairment assessment uses a discounted cash flow income approach, including consideration of the severity and duration of any decline in fair value of our investment in the project. Our key inputs involve significant management judgments and estimates, including projections of the project's cash flows, selection of a discount rate and probability weighting of potential outcomes of legal and regulatory proceedings. Based upon these estimates using information known as of December 31, 2017, the fair value of Duke Energy's investment in Constitution approximated its carrying value. As a result, Duke Energy did not recognize any impairment charge in the year ended December 31, 2017. However, due to the FERC's January 2018 ruling and the resulting increase in uncertainty, Duke Energy is evaluating the potential to recognize a pretax impairment charge on its investment in Constitution during the first quarter of 2018 of up to the current carrying amount of the investment, net of salvage value and any cash and working capital returned. For additional information on the Constitution investment, see Note 4.

During the year ended December 31, 2016, Duke Energy recorded an OTTI of certain wind project investments. The $71 million pretax impairment was recorded within Equity in earnings (losses) of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations. The other-than-temporary decline in value of these investments was primarily attributable to a sustained decline in market pricing where the wind investments are located, projected net losses for the projects and a reduction in the projected cash distribution to the class of investment owned by Duke Energy.

Other

Duke Energy owns a 17.5 percent indirect interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia. Duke Energy's economic ownership interest decreased from 25 percent to 17.5 percent with the successful startup of NMC's polyacetal production facility in 2017. Duke Energy retains 25 percent of the board representation and voting rights of NMC. The investment in NMC is accounted for under the equity method of accounting.

13. RELATED PARTY TRANSACTIONS

The Subsidiary Registrants engage in related party transactions in accordance with the applicable state and federal commission regulations. Refer to the Consolidated Balance Sheets of the Subsidiary Registrants for balances due to or due from related parties. Material amounts related to transactions with related parties included in the Consolidated Statements of Operations and Comprehensive Income are presented in the following table.

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Duke Energy Carolinas			
Corporate governance and shared service expenses[a]	**$ 858**	$ 831	$ 914
Indemnification coverages[b]	**23**	22	24
JDA revenue[c]	**49**	38	51
JDA expense[c]	**145**	156	183
Intercompany natural gas purchases[d]	**9**	2	—
Progress Energy			
Corporate governance and shared service expenses[a]	**$ 736**	$ 710	$ 712
Indemnification coverages[b]	**38**	35	38
JDA revenue[c]	**145**	156	183
JDA expense[c]	**49**	38	51
Intercompany natural gas purchases[d]	**77**	19	—
Duke Energy Progress			

Corporate governance and shared service expenses[a]	**$**	**438**	$	397	$	403
Indemnification coverages[b]		**15**		14		16
JDA revenue[c]		**145**		156		183
JDA expense[c]		**49**		38		51
Intercompany natural gas purchases[d]		**77**		19		—
Duke Energy Florida						
Corporate governance and shared service expenses[a]	**$**	**298**	$	313	$	309
Indemnification coverages[b]		**23**		21		22
Duke Energy Ohio						
Corporate governance and shared service expenses[a]	**$**	**363**	$	356	$	342
Indemnification coverages[b]		**5**		5		6
Duke Energy Indiana						
Corporate governance and shared service expenses[a]	**$**	**370**	$	366	$	349
Indemnification coverages[b]		**8**		8		9
Piedmont						
Corporate governance and shared service expenses[a]	**$**	**50**				
Indemnification coverages[b]		**2**				
Intercompany natural gas sales[d]		**86**				

(w) The Subsidiary Registrants are charged their proportionate share of corporate governance and other shared services costs, primarily related to human resources, employee benefits, information technology, legal and accounting fees, as well as other third-party costs. These amounts are primarily recorded in Operation, maintenance and other on the Consolidated Statements of Operations and Comprehensive Income.

(x) The Subsidiary Registrants incur expenses related to certain indemnification coverages through Bison, Duke Energy's wholly owned captive insurance subsidiary. These expenses are recorded in Operation, maintenance and other on the Consolidated Statements of Operations and Comprehensive Income.

(y) Duke Energy Carolinas and Duke Energy Progress participate in a JDA, which allows the collective dispatch of power plants between the service territories to reduce customer rates. Revenues from the sale of power and expenses from the purchase of power pursuant to the JDA are recorded in Operating Revenues and Fuel used in electric generation and purchased power, respectively, on the Consolidated Statements of Operations and Comprehensive Income.

(z) Piedmont provides long-term natural gas delivery service to certain Duke Energy Carolinas and Duke Energy Progress natural gas-fired generation facilities. Piedmont records the sales in Regulated natural gas revenues, and Duke Energy Carolinas and Duke Energy Progress record the related purchases in Fuel used in electric generation and purchased power on their respective Consolidated Statements of Operations and Comprehensive Income. The amounts are not eliminated in accordance with rate-based accounting regulations. For the two months ended December 31, 2016, and for sales made subsequent to the acquisition for the year ended October 31, 2016, Piedmont recorded $14 million and $7 million, respectively, of natural gas sales with Duke Energy. For sales made prior to the acquisition for the year ended October 31, 2016, and for the year ended October 31, 2015, Piedmont recorded $74 million and $83 million, respectively of natural gas sales with Duke Energy.

In addition to the amounts presented above, the Subsidiary Registrants have other affiliate transactions, including rental of office space, participation in a money pool arrangement, other operational transactions and their proportionate share of certain charged expenses. See Note 6 for more information regarding money pool. These transactions of the Subsidiary Registrants were not material for the years ended December 31, 2017, 2016 and 2015.

As discussed in Note 17, certain trade receivables have been sold by Duke Energy Ohio and Duke Energy Indiana to CRC, an affiliate formed by a subsidiary of Duke Energy. The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from CRC for a portion of the purchase price.

Refer to Note 2 for further information on the sale of the Midwest Generation Disposal Group.

Equity Method Investments

Piedmont has related party transactions as a customer of its equity method investments in natural gas storage and transportation facilities. The following table presents expenses that are included in Cost of natural gas on Piedmont's Consolidated Statements of Operations and Comprehensive Income.

		Year Ended December 31,	Two Months Ended December 31,	Years Ended October 31,	
(in millions)	**Type of expense**	**2017**	**2016**	**2016**	**2015**
Cardinal	Transportation Costs	**$ 8**	$ 2	$ 9	$ 9
Pine Needle	Natural Gas Storage Costs	**8**	2	11	11
Hardy Storage	Natural Gas Storage Costs	**9**	2	9	9
Total		**$ 25**	$ 6	$ 29	$ 29

Piedmont had accounts payable to its equity method investments of $2 million at December 31, 2017, and 2016 related to these transactions. These amounts are included in Accounts payable on the Consolidated Balance Sheets.

Intercompany Income Taxes

Duke Energy and the Subsidiary Registrants file a consolidated federal income tax return and other state and jurisdictional returns. The Subsidiary Registrants have a tax sharing agreement with Duke Energy for the allocation of consolidated tax liabilities and benefits. Income taxes recorded represent amounts the Subsidiary Registrants would incur as separate C-Corporations. The following table includes the balance of intercompany income tax receivables and payables for the Subsidiary Registrants.

(in millions)	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
December 31, 2017							
Intercompany income tax receivable	**$ —**	**$ 168**	**$ —**	**$ 44**	**$ 22**	**$ —**	**$ 7**
Intercompany income tax payable	**44**	**—**	**21**	**—**	**—**	**35**	**—**
December 31, 2016							
Intercompany income tax receivable	$ 1	$ —	$ —	$ 37	$ —	$ —	$ —
Intercompany income tax payable	—	37	90	—	1	3	38

14. DERIVATIVES AND HEDGING

The Duke Energy Registrants use commodity and interest rate contracts to manage commodity price risk and interest rate risk. The primary use of commodity derivatives is to hedge the generation portfolio against changes in the prices of electricity and natural gas. Piedmont enters into natural gas supply contracts to provide diversification, reliability and natural gas cost benefits to its customers. Interest rate swaps are used to manage interest rate risk associated with borrowings.

All derivative instruments not identified as NPNS are recorded at fair value as assets or liabilities on the Consolidated Balance Sheets. Cash collateral related to derivative instruments executed under master netting arrangements is offset against the collateralized derivatives on the Consolidated Balance Sheets. The cash impacts of settled derivatives are recorded as operating activities on the Consolidated Statements of Cash Flows.

INTEREST RATE RISK

The Duke Energy Registrants are exposed to changes in interest rates as a result of their issuance or anticipated issuance of variable-rate and fixed-rate debt and commercial paper. Interest rate risk is managed by limiting variable-rate exposures to a percentage of total debt and by monitoring changes in interest rates. To manage risk associated with changes in interest rates, the Duke Energy Registrants may enter into interest rate swaps, U.S. Treasury lock agreements and other financial contracts. In anticipation of certain fixed-rate debt issuances, a series of forward-starting interest rate swaps may be executed to lock in components of current market interest rates. These instruments are later terminated prior to or upon the issuance of the corresponding debt.

Cash Flow Hedges

For a derivative designated as hedging the exposure to variable cash flows of a future transaction, referred to as a cash flow hedge, the effective portion of the derivative's gain or loss is initially reported as a component of other comprehensive income and subsequently reclassified into earnings once the future transaction impacts earnings. Amounts for interest rate contracts are reclassified to earnings as interest expense over the term of the related debt. See the Consolidated Statements of Changes in Equity for gains and losses reclassified out of AOCI for the years ended December 31, 2017, and 2016. Duke Energy's interest rate derivatives designated as hedges include interest rate swaps used to hedge existing debt within the Commercial Renewables business.

Undesignated Contracts

Undesignated contracts include contracts not designated as a hedge because they are accounted for under regulatory accounting and contracts that do not qualify for hedge accounting.

Duke Energy's interest rate swaps for its regulated operations employ regulatory accounting. With regulatory accounting, the mark-to-market gains or losses on the swaps are deferred as regulatory liabilities or regulatory assets, respectively. Regulatory assets and liabilities are amortized consistent with the treatment of the related costs in the ratemaking process. The accrual of interest on the swaps is recorded as Interest Expense.

In August 2016, Duke Energy unwound $1.4 billion of forward-starting interest rate swaps associated with the Piedmont acquisition financing described in Note 6. The swaps were considered undesignated as they did not qualify for hedge accounting. Losses on the swaps of $190 million are included within Interest Expense on the Consolidated Statements of Operations for the year ended December 31, 2016. See Note 2 for additional information related to the Piedmont acquisition.

The following tables show notional amounts of outstanding derivatives related to interest rate risk.

	December 31, 2017					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio
Cash flow hedges[a]	$ 660	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	927	400	500	250	250	27
Total notional amount	$ 1,587	$ 400	$ 500	$ 250	$ 250	$ 27

	December 31, 2016					
		Duke		Duke	Duke	Duke

(in millions)	Duke Energy	Energy Carolinas	Progress Energy	Energy Progress	Energy Florida	Energy Ohio
Cash flow hedges[(a)]	$ 750	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	927	400	500	250	250	27
Total notional amount	$ 1,677	$ 400	$ 500	$ 250	$ 250	$ 27

(a) Duke Energy includes amounts related to consolidated VIEs of $660 million and $750 million at December 31, 2017, and 2016, respectively. During 2016, Duke Energy entered into interest rate swaps related to solar financing with an outstanding notional amount of $300 million, including $81 million of four-year swaps and $219 million of 18-year swaps, at December 31, 2016. See note 6 for additional information related to the solar facilities financing.

COMMODITY PRICE RISK

The Duke Energy Registrants are exposed to the impact of changes in the prices of electricity purchased and sold in bulk power markets and coal and natural gas purchases, including Piedmont's natural gas supply contracts. Exposure to commodity price risk is influenced by a number of factors including the term of contracts, the liquidity of markets and delivery locations. For the Subsidiary Registrants, bulk power electricity and coal and natural gas purchases flow through fuel adjustment clauses, formula based contracts or other cost sharing mechanisms. Differences between the costs included in rates and the incurred costs, including undesignated derivative contracts, are largely deferred as regulatory assets or regulatory liabilities. Piedmont policies allow for the use of financial instruments to hedge commodity price risks. The strategy and objective of these hedging programs are to use the financial instruments to reduce gas cost volatility for customers.

Volumes

The tables below include volumes of outstanding commodity derivatives. Amounts disclosed represent the absolute value of notional volumes of commodity contracts excluding NPNS. The Duke Energy Registrants have netted contractual amounts where offsetting purchase and sale contracts exist with identical delivery locations and times of delivery. Where all commodity positions are perfectly offset, no quantities are shown.

	December 31, 2017						
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Piedmont
Electricity (gigawatt-hours)	**34**	**—**	**—**	**—**	**—**	**34**	**—**
Natural gas (millions of dekatherms)	**770**	**105**	**183**	**133**	**50**	**2**	**480**

	December 31, 2016						
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Piedmont
Electricity (gigawatt-hours)	147	—	—	—	—	147	—
Natural gas (millions of dekatherms)	890	91	269	118	151	1	529

LOCATION AND FAIR VALUE OF DERIVATIVE ASSETS AND LIABILITIES RECOGNIZED IN THE CONSOLIDATED BALANCE SHEETS

The following tables show the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the Consolidated Balance Sheets, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Derivative Assets	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 34	$ 2	$ 2	$ 1	$ 1	$ 1	$ 27	$ 2
Noncurrent	1	—	1	1	—	—	—	—
Total Derivative Assets – Commodity Contracts	$ 35	$ 2	$ 3	$ 2	$ 1	$ 1	$ 27	$ 2
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	15	—	—	—	—	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 16	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total Derivative Assets	$ 51	$ 2	$ 3	$ 2	$ 1	$ 1	$ 27	$ 2

Derivative Liabilities	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 36	$ 6	$ 18	$ 8	$ 10	$ —	$ —	$ 11
Noncurrent	146	4	10	4	—	—	—	131
Total Derivative Liabilities – Commodity Contracts	$ 182	$ 10	$ 28	$ 12	$ 10	$ —	$ —	$ 142
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 29	$ 25	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	6	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	1	—	1	—	—	1	—	—
Noncurrent	12	—	7	6	2	4	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 48	$ 25	$ 8	$ 6	$ 2	$ 5	$ —	$ —
Total Derivative Liabilities	$ 230	$ 35	$ 36	$ 18	$ 12	$ 5	$ —	$ 142

Derivative Assets	December 31, 2016						
	Duke	Duke Energy	Progress	Duke Energy	Duke Energy	Duke Energy	Duke Energy

(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 108	$ 23	$ 61	$ 35	$ 26	$ 4	$ 16	$ 3
Noncurrent	32	10	21	10	11	1	—	—
Total Derivative Assets – Commodity Contracts	$ 140	$ 33	$ 82	$ 45	$ 37	$ 5	$ 16	$ 3
Interest Rate Contracts								
Designated as Hedging Instruments								
Noncurrent	$ 19	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Not Designated as Hedging Instruments								
Current	3	—	3	1	2	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 22	$ —	$ 3	$ 1	$ 2	$ —	$ —	$ —
Total Derivative Assets	$ 162	$ 33	$ 85	$ 46	$ 39	$ 5	$ 16	$ 3

Derivative Liabilities	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 43	$ —	$ 12	$ —	$ 12	$ —	$ 2	$ 35
Noncurrent	166	1	7	1	—	—	—	152
Total Derivative Liabilities – Commodity Contracts	$ 209	$ 1	$ 19	$ 1	$ 12	$ —	$ 2	$ 187
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 8	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	8	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	1	—	—	—	—	1	—	—
Noncurrent	26	15	6	6	—	5	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 43	$ 15	$ 6	$ 6	$ —	$ 6	$ —	$ —
Total Derivative Liabilities	$ 252	$ 16	$ 25	$ 7	$ 12	$ 6	$ 2	$ 187

OFFSETTING ASSETS AND LIABILITIES

The following tables present the line items on the Consolidated Balance Sheets where derivatives are reported. Substantially all of Duke Energy's outstanding derivative contracts are subject to enforceable master netting arrangements. The Gross amounts offset in the tables below show the effect of these netting arrangements on financial position and include collateral posted to offset the net position. The amounts shown are calculated by counterparty. Accounts receivable or accounts payable may also be available to offset exposures in the event of bankruptcy. These amounts are not included in the tables below.

Derivative Assets	December 31, 2017							
		Duke		Duke	Duke	Duke	Duke	

(in millions)	Duke Energy	Energy Carolinas	Progress Energy	Energy Progress	Energy Florida	Energy Ohio	Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 35	$ 2	$ 2	$ 1	$ 1	$ 1	$ 27	$ 2
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Current Assets: Other	$ 35	$ 2	$ 2	$ 1	$ 1	$ 1	$ 27	$ 2
Noncurrent								
Gross amounts recognized	$ 16	$ —	$ 1	$ 1	$ —	$ —	$ —	$ —
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 16	$ —	$ 1	$ 1	$ —	$ —	$ —	$ —

Derivative Liabilities	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 66	$ 31	$ 19	$ 8	$ 10	$ 1	$ —	$ 11
Gross amounts offset	(3)	(2)	(2)	(2)	—	—	—	—
Net amounts presented in Current Liabilities: Other	$ 63	$ 29	$ 17	$ 6	$ 10	$ 1	$ —	$ 11
Noncurrent								
Gross amounts recognized	$ 164	$ 4	$ 17	$ 10	$ 2	$ 4	$ —	$ 131
Gross amounts offset	(1)	—	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 163	$ 4	$ 16	$ 9	$ 2	$ 4	$ —	$ 131

Derivative Assets	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 111	$ 23	$ 64	$ 36	$ 28	$ 4	$ 16	$ 3
Gross amounts offset	(11)	—	(11)	—	(11)	—	—	—
Net amounts presented in Current Assets: Other	$ 100	$ 23	$ 53	$ 36	$ 17	$ 4	$ 16	$ 3
Noncurrent								
Gross amounts recognized	$ 51	$ 10	$ 21	$ 10	$ 11	$ 1	$ —	$ —
Gross amounts offset	(2)	(1)	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 49	$ 9	$ 20	$ 9	$ 11	$ 1	$ —	$ —

Derivative Liabilities	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 52	$ —	$ 12	$ —	$ 12	$ 1	$ 2	$ 35
Gross amounts offset	(11)	—	(11)	—	(11)	—	—	—
Net amounts presented in Current Liabilities: Other	$ 41	$ —	$ 1	$ —	$ 1	$ 1	$ 2	$ 35
Noncurrent								
Gross amounts recognized	$ 200	$ 16	$ 13	$ 7	$ —	$ 5	$ —	$ 152
Gross amounts offset	(2)	(1)	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 198	$ 15	$ 12	$ 6	$ —	$ 5	$ —	$ 152

OBJECTIVE CREDIT CONTINGENT FEATURES

Certain derivative contracts contain objective credit contingent features. These features include the requirement to post cash collateral or letters of credit if specific events occur, such as a credit rating downgrade below investment grade. The following tables show information with respect to derivative contracts that are in a net liability position and contain objective credit-risk-related payment provisions.

	December 31, 2017				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Aggregate fair value of derivatives in a net liability position	**$ 59**	**$ 35**	**$ 25**	**$ 15**	**$ 10**
Fair value of collateral already posted	**—**	**—**	**—**	**—**	**—**
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	**59**	**35**	**25**	**15**	**10**

	December 31, 2016				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Aggregate fair value of derivatives in a net liability position	$ 34	$ 16	$ 18	$ 6	$ 12
Fair value of collateral already posted	—	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	34	16	18	6	12

The Duke Energy Registrants have elected to offset cash collateral and fair values of derivatives. For amounts to be netted, the derivative and cash collateral must be executed with the same counterparty under the same master netting arrangement.

15. INVESTMENTS IN DEBT AND EQUITY SECURITIES

The Duke Energy Registrants classify their investments in debt and equity securities as either trading or available-for-sale.

TRADING SECURITIES

Piedmont's investments in debt and equity securities held in rabbi trusts associated with certain deferred compensation plans are classified as trading securities. The fair value of these investments was $1 million and $5 million as of December 31, 2017, and 2016, respectively.

AVAILABLE-FOR-SALE (AFS) SECURITIES

All other investments in debt and equity securities are classified as AFS.

Duke Energy’s AFS securities are primarily comprised of investments held in (i) the nuclear decommissioning trust funds (NDTF) at Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, (ii) grantor trusts at Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana related to OPEB plans and (iii) Bison.

Duke Energy classifies all other investments in debt and equity securities as long term, unless otherwise noted.

Investment Trusts

The investments within the NDTF investments and the Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana grantor trusts (Investment Trusts) are managed by independent investment managers with discretion to buy, sell and invest pursuant to the objectives set forth by the trust agreements. The Duke Energy Registrants have limited oversight of the day-to-day management of these investments. As a result, the ability to hold investments in unrealized loss positions is outside the control of the Duke Energy Registrants. Accordingly, all unrealized losses associated with debt and equity securities within the Investment Trusts are considered OTTIs and are recognized immediately.

Investments within the Investment Trusts generally qualify for regulatory accounting and accordingly realized and unrealized gains and losses are generally deferred as a regulatory asset or liability.

Substantially all amounts of the Duke Energy Registrants' gross unrealized holding losses as of December 31, 2017, and 2016, are considered OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.

Other AFS Securities

Unrealized gains and losses on all other AFS securities are included in other comprehensive income until realized, unless it is determined the carrying value of an investment is other-than-temporarily impaired. If an OTTI exists, the unrealized loss is included in earnings based on the criteria discussed below.

The Duke Energy Registrants analyze all investment holdings each reporting period to determine whether a decline in fair value should be considered other-than-temporary. Criteria used to evaluate whether an impairment associated with equity securities is other-than-temporary includes, but is not limited to, (i) the length of time over which the market value has been lower than the cost basis of the investment, (ii) the percentage decline compared to the cost of the investment and (iii) management’s intent and ability to retain its investment for a period of time sufficient to allow for any anticipated recovery in market value. If a decline in fair value is determined to be other-than-temporary, the investment is written down to its fair value through a charge to earnings.

If the entity does not have an intent to sell a debt security and it is not more likely than not management will be required to sell the debt security before the recovery of its cost basis, the impairment write-down to fair value would be recorded as a component of other comprehensive income, except for when it is determined a credit loss exists. In determining whether a credit loss exists, management considers, among other things, (i) the length of time and the extent to which the fair value has been less than the amortized cost basis, (ii) changes in the financial condition of the issuer of the security, or in the case of an asset backed security, the financial condition of the underlying loan obligors, (iii) consideration of underlying collateral and guarantees of amounts by government entities, (iv) ability of the issuer of the security to make scheduled interest or principal payments and (v) any changes to the rating of the security by rating agencies. If a credit loss exists, the amount of impairment write-down to fair value is split between credit loss and other factors. The amount related to credit loss is recognized in earnings. The amount related to other factors is recognized in other comprehensive income. There were no material credit losses as of December 31, 2017, and 2016.

Other Investments amounts are recorded in Other within Other Noncurrent Assets on the Consolidated Balance Sheets.

DUKE ENERGY

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 115**	$ —	$ —	$ 111
Equity securities	**2,805**	**27**	**4,914**	2,092	54	4,106
Corporate debt securities	**17**	**2**	**570**	10	8	528
Municipal bonds	**4**	**3**	**344**	3	10	331
U.S. government bonds	**11**	**7**	**1,027**	10	8	984
Other debt securities	**—**	**1**	**118**	—	3	124
Total NDTF	**$ 2,837**	**$ 40**	**$ 7,088**	$ 2,115	$ 83	$ 6,184
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 15**	$ —	$ —	$ 25
Equity securities	**59**	**—**	**123**	38	—	104
Corporate debt securities	**1**	**—**	**57**	1	1	66
Municipal bonds	**2**	**1**	**83**	2	1	82
U.S. government bonds	**—**	**—**	**41**	—	1	51
Other debt securities	**—**	**1**	**44**	—	2	42
Total Other Investments	**$ 62**	**$ 2**	**$ 363**	$ 41	$ 5	$ 370
Total Investments	**$ 2,899**	**$ 42**	**$ 7,451**	$ 2,156	$ 88	$ 6,554

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	**$ 117**
Due after one through five years	**552**
Due after five through 10 years	**554**
Due after 10 years	**1,061**
Total	**$ 2,284**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	**2017**	2016	2015
Realized gains	**$ 202**	$ 246	$ 193
Realized losses	**160**	187	98

DUKE ENERGY CAROLINAS

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 32**	$ —	$ —	$ 18
Equity securities	**1,531**	**12**	**2,692**	1,157	28	2,245
Corporate debt securities	**9**	**2**	**359**	5	6	354
Municipal bonds	**—**	**1**	**60**	1	2	67
U.S. government bonds	**3**	**4**	**503**	2	5	458
Other debt securities	**—**	**1**	**112**	—	3	116
Total NDTF	**$ 1,543**	**$ 20**	**$ 3,758**	$ 1,165	$ 44	$ 3,258
Other Investments						
Other debt securities	**$ —**	**$ —**	**$ —**	$ —	$ 1	$ 3
Total Other Investments	**$ —**	**$ —**	**$ —**	$ —	$ 1	$ 3
Total Investments	**$ 1,543**	**$ 20**	**$ 3,758**	$ 1,165	$ 45	$ 3,261

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	**$ 9**
Due after one through five years	**204**
Due after five through 10 years	**300**
Due after 10 years	**521**
Total	**$ 1,034**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	**2017**	2016	2015
Realized gains	**$ 135**	$ 157	$ 158
Realized losses	**103**	121	83

PROGRESS ENERGY

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	$ —	$ —	$ 83	$ —	$ —	$ 93
Equity securities	1,274	15	2,222	935	26	1,861
Corporate debt securities	8	—	211	5	2	174
Municipal bonds	4	2	284	2	8	264
U.S. government bonds	8	3	524	8	3	526
Other debt securities	—	—	6	—	—	8
Total NDTF	$ 1,294	$ 20	$ 3,330	$ 950	$ 39	$ 2,926
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 12	$ —	$ —	$ 21
Municipal bonds	2	—	47	2	—	44
Total Other Investments	$ 2	$ —	$ 59	$ 2	$ —	$ 65
Total Investments	$ 1,296	$ 20	$ 3,389	$ 952	$ 39	$ 2,991

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	$ 94
Due after one through five years	301
Due after five through 10 years	203
Due after 10 years	474
Total	$ 1,072

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	**2017**	2016	2015
Realized gains	$ 65	$ 84	$ 33
Realized losses	56	64	13

DUKE ENERGY PROGRESS

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 50**	$ —	$ —	$ 45
Equity securities	**980**	**12**	**1,795**	704	21	1,505
Corporate debt securities	**6**	**—**	**149**	4	1	120
Municipal bonds	**4**	**2**	**283**	2	8	263
U.S. government bonds	**5**	**2**	**310**	5	2	275
Other debt securities	**—**	**—**	**4**	—	—	5
Total NDTF	**$ 995**	**$ 16**	**$ 2,591**	$ 715	$ 32	$ 2,213
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ 1
Total Other Investments	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ 1
Total Investments	**$ 995**	**$ 16**	**$ 2,592**	$ 715	$ 32	$ 2,214

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	**$ 21**
Due after one through five years	**219**
Due after five through 10 years	**146**
Due after 10 years	**360**
Total	**$ 746**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	**2017**	2016	2015
Realized gains	**$ 54**	$ 71	$ 26
Realized losses	**48**	55	11

DUKE ENERGY FLORIDA

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017			December 31, 2016		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 33**	$ —	$ —	$ 48
Equity securities	**294**	**3**	**427**	231	5	356
Corporate debt securities	**2**	**—**	**62**	1	1	54
Municipal bonds	**—**	**—**	**1**	—	—	1
U.S. government bonds	**3**	**1**	**214**	3	1	251
Other debt securities	**—**	**—**	**2**	—	—	3
Total NDTF(a)	**$ 299**	**$ 4**	**$ 739**	$ 235	$ 7	$ 713
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ 4
Municipal bonds	**2**	**—**	**47**	2	—	44
Total Other Investments	**$ 2**	**$ —**	**$ 48**	$ 2	$ —	$ 48
Total Investments	**$ 301**	**$ 4**	**$ 787**	$ 237	$ 7	$ 761

(a) During the year ended December 31, 2017, Duke Energy Florida continued to receive reimbursements from the NDTF for costs related to ongoing decommissioning activity of the Crystal River Unit 3 nuclear plant.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2017**
Due in one year or less	**$ 73**
Due after one through five years	**82**
Due after five through 10 years	**57**
Due after 10 years	**114**
Total	**$ 326**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were as follows.

	Years Ended December 31,		
(in millions)	**2017**	2016	2015
Realized gains	**$ 11**	$ 13	$ 7
Realized losses	**8**	9	2

DUKE ENERGY INDIANA

The following table presents the estimated fair value of investments in AFS securities.

	December 31, 2017		December 31, 2016	
	Gross	**Gross**	**Gross**	**Gross**

(in millions)	Unrealized Holding Gains	Unrealized Holding Losses	Estimated Fair Value	Unrealized Holding Gains	Unrealized Holding Losses(a)	Estimated Fair Value
Other Investments						
Equity securities	**$ 49**	**$ —**	**$ 97**	$ 33	$ —	$ 79
Corporate debt securities	**—**	**—**	**3**	—	—	2
Municipal bonds	**—**	**1**	**28**	—	1	28
U.S. government bonds	**—**	**—**	**—**	—	—	1
Total Other Investments	**$ 49**	**$ 1**	**$ 128**	$ 33	$ 1	$ 110
Total Investments	**$ 49**	**$ 1**	**$ 128**	$ 33	$ 1	$ 110

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2017
Due in one year or less	**$ 5**
Due after one through five years	**12**
Due after five through 10 years	**7**
Due after 10 years	**7**
Total	**$ 31**

Realized gains and losses, which were determined on a specific identification basis, from sales of AFS securities were insignificant for the years ended December 31, 2017, 2016 and 2015.

16. FAIR VALUE MEASUREMENTS

Fair value is the exchange price to sell an asset or transfer a liability in an orderly transaction between market participants at the measurement date. The fair value definition focuses on an exit price versus the acquisition cost. Fair value measurements use market data or assumptions market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs may be readily observable, corroborated by market data, or generally unobservable. Valuation techniques maximize the use of observable inputs and minimize use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

Fair value measurements are classified in three levels based on the fair value hierarchy:

Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities that the reporting entity can access at the measurement date. An active market is one in which transactions for an asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 – A fair value measurement utilizing inputs other than quoted prices included in Level 1 that are observable, either directly or indirectly, for an asset or liability. Inputs include (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in markets that are not active, and (iii) inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities and credit spreads. A Level 2 measurement cannot have more than an insignificant portion of its valuation based on unobservable inputs. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – Any fair value measurement which includes unobservable inputs for more than an insignificant portion of the valuation. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 measurements may include longer-term instruments that extend into periods in which observable inputs are not available.

Not Categorized – Certain investments are not categorized within the Fair Value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Fair value accounting guidance permits entities to elect to measure certain financial instruments that are not required to be accounted for at fair value, such as equity method investments or the company's own debt, at fair value. The Duke Energy Registrants have not elected to record any of these items at fair value.

Transfers between levels represent assets or liabilities that were previously (i) categorized at a higher level for which the inputs to the estimate became less observable or (ii) classified at a lower level for which the inputs became more observable during the period. The Duke Energy Registrant's policy is to recognize transfers between levels of the fair value hierarchy at the end of the period. There were no transfers between levels during the years ended December 31, 2017, 2016 and 2015. In addition, for Piedmont, there were no transfers between levels during the two months ended December 31, 2016, and the years ended October 31, 2016, and 2015.

Valuation methods of the primary fair value measurements disclosed below are as follows.

Investments in equity securities

The majority of investments in equity securities are valued using Level 1 measurements. Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the quarter. Principal active markets for equity prices include published exchanges such as the New York Stock Exchange (NYSE) and the NASDAQ Stock Market. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. There was no after-hours market activity that was required to be reflected in the reported fair value measurements.

Investments in debt securities

Most investments in debt securities are valued using Level 2 measurements because the valuations use interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. If the market for a particular fixed-income security is relatively inactive or illiquid, the measurement is Level 3.

Commodity derivatives

Commodity derivatives with clearinghouses are classified as Level 1. Other commodity derivatives, including Piedmont's natural gas supply contracts, are primarily valued using internally developed discounted cash flow models that incorporate forward price, adjustments for liquidity (bid-ask spread) and credit or non-performance risk (after reflecting credit enhancements such as collateral) and are discounted to present value. Pricing inputs are derived from published exchange transaction prices and other observable data sources. In the absence of an active market, the last available price may be used. If forward price curves are not observable for the full term of the contract and the unobservable period had more than an insignificant impact on the valuation, the commodity derivative is classified as Level 3. In isolation, increases (decreases) in natural gas forward prices result in favorable (unfavorable) fair value adjustments for gas purchase contracts; and increases (decreases) in electricity forward prices result in unfavorable (favorable) fair value adjustments for electricity sales contracts. Duke Energy regularly evaluates and validates pricing inputs used to estimate the fair value of natural gas commodity contracts by a market participant price verification procedure. This procedure provides a comparison of internal forward commodity curves to market participant generated curves.

Interest rate derivatives

Most over-the-counter interest rate contract derivatives are valued using financial models that utilize observable inputs for similar instruments and are classified as Level 2. Inputs include forward interest rate curves, notional amounts, interest rates and credit quality of the counterparties.

Other fair value considerations

See Note 11 for a discussion of the valuation of goodwill and intangible assets. See Note 2 related to the acquisition of Piedmont in 2016 and the purchase of NCEMPA's ownership interests in certain generating assets in 2015.

DUKE ENERGY

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets. Derivative amounts in the table below for all Duke Energy Registrants exclude cash collateral, which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type for the Duke Energy Registrants.

	December 31, 2017				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
NDTF equity securities	$ 4,914	$ 4,840	$ —	$ —	$ 74
NDTF debt securities	2,174	635	1,539	—	—
Other AFS equity securities	123	123	—	—	—
Other trading and AFS debt securities	241	57	184	—	—
Derivative assets	51	3	20	28	—
Total assets	7,503	5,658	1,743	28	74
Derivative liabilities	(230)	(2)	(86)	(142)	—
Net assets (liabilities)	$ 7,273	$ 5,656	$ 1,657	$ (114)	$ 74

	December 31, 2016				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
NDTF equity securities	$ 4,106	$ 4,029	$ —	$ —	$ 77
NDTF debt securities	2,078	632	1,446	—	—
Other trading and AFS equity securities	104	104	—	—	—
Other trading and AFS debt securities	266	75	186	5	—
Derivative assets	162	5	136	21	—
Total assets	6,716	4,845	1,768	26	77
Derivative liabilities	(252)	(2)	(63)	(187)	—
Net assets	$ 6,464	$ 4,843	$ 1,705	$ (161)	$ 77

The following tables provide reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements. Amounts included in earnings for derivatives are primarily included in Cost of natural gas on the Duke Energy Registrants' Consolidated Statements of Operations and Comprehensive Income. Amounts included in changes of net assets on the Duke Energy Registrants' Consolidated Balance Sheets are included in regulatory assets or liabilities. All derivative assets and liabilities are presented on a net basis.

	December 31, 2017			December 31, 2016		
(in millions)	Investments	Derivatives (net)	Total	Investments	Derivatives (net)	Total
Balance at beginning of period	$ 5	$ (166)	$ (161)	$ 5	$ 10	$ 15
Total pretax realized or unrealized gains included in comprehensive income	1	—	1	—	—	—
Derivative liability resulting from the acquisition of Piedmont	—	—	—	—	(187)	(187)
Purchases, sales, issuances and settlements:						
Purchases	—	55	55	—	33	33

Sales	(6)	—	(6)	—	—	—
Settlements	—	(47)	(47)	—	(28)	(28)
Total gains included on the Consolidated Balance Sheet	—	44	44	—	6	6
Balance at end of period	$ —	$ (114)	$ (114)	$ 5	$ (166)	$ (161)

DUKE ENERGY CAROLINAS

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
NDTF equity securities	$ 2,692	$ 2,618	$ —	$ —	$ 74
NDTF debt securities	1,066	204	862	—	—
Derivative assets	2	—	2	—	—
Total assets	3,760	2,822	864	—	74
Derivative liabilities	(35)	(1)	(34)	—	—
Net assets	$ 3,725	$ 2,821	$ 830	$ —	$ 74

	December 31, 2016				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
NDTF equity securities	$ 2,245	$ 2,168	$ —	$ —	$ 77
NDTF debt securities	1,013	178	835	—	—
Other AFS debt securities	3	—	—	3	—
Derivative assets	33	—	33	—	—
Total assets	3,294	2,346	868	3	77
Derivative liabilities	(16)	—	(16)	—	—
Net assets	$ 3,278	$ 2,346	$ 852	$ 3	$ 77

The following table provides reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Investments	
	Years Ended December 31,	
(in millions)	2017	2016
Balance at beginning of period	$ 3	$ 3
Total pretax realized or unrealized gains included in comprehensive income	1	—
Purchases, sales, issuances and settlements:		
Sales	(4)	—
Balance at end of period	$ —	$ 3

PROGRESS ENERGY

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 2,222**	**$ 2,222**	**$ —**	$ 1,861	$ 1,861	$ —
NDTF debt securities	**1,108**	**431**	**677**	1,065	454	611
Other AFS debt securities	**59**	**12**	**47**	65	21	44
Derivative assets	**3**	**1**	**2**	85	—	85
Total assets	**3,392**	**2,666**	**726**	3,076	2,336	740
Derivative liabilities	**(36)**	**(1)**	**(35)**	(25)	—	(25)
Net assets	**$ 3,356**	**$ 2,665**	**$ 691**	$ 3,051	$ 2,336	$ 715

DUKE ENERGY PROGRESS

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 1,795**	**$ 1,795**	**$ —**	$ 1,505	$ 1,505	$ —
NDTF debt securities	**796**	**243**	**553**	708	207	501
Other AFS debt securities	**1**	**1**	**—**	1	1	—
Derivative assets	**2**	**1**	**1**	46	—	46
Total assets	**2,594**	**2,040**	**554**	2,260	1,713	547
Derivative liabilities	**(18)**	**(1)**	**(17)**	(7)	—	(7)
Net assets	**$ 2,576**	**$ 2,039**	**$ 537**	$ 2,253	$ 1,713	$ 540

DUKE ENERGY FLORIDA

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 427**	**$ 427**	**$ —**	$ 356	$ 356	$ —
NDTF debt securities	**312**	**188**	**124**	357	247	110
Other AFS debt securities	**48**	**1**	**47**	48	4	44
Derivative assets	**1**	**—**	**1**	39	—	39
Total assets	**788**	**616**	**172**	800	607	193
Derivative liabilities	**(12)**	**—**	**(12)**	(12)	—	(12)
Net assets	**$ 776**	**$ 616**	**$ 160**	$ 788	$ 607	$ 181

DUKE ENERGY OHIO

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 2**	**Level 3**	**Total Fair Value**	**Level 2**	**Level 3**
Derivative assets	**$ 1**	**$ —**	**$ 1**	$ 5	$ —	$ 5
Derivative liabilities	**(5)**	**(5)**	**—**	(6)	(6)	—
Net (liabilities) assets	**$ (4)**	**$ (5)**	**$ 1**	$ (1)	$ (6)	$ 5

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Derivatives (net)	
	Years Ended December 31,	
(in millions)	**2017**	**2016**
Balance at beginning of period	**$ 5**	$ 3
Purchases, sales, issuances and settlements:		
Purchases	**3**	5
Settlements	**(4)**	(5)
Total gains included on the Consolidated Balance Sheet	**(3)**	2
Balance at end of period	**$ 1**	$ 5

DUKE ENERGY INDIANA

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017				December 31, 2016			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Other AFS equity securities	**$ 97**	**$ 97**	**$ —**	**$ —**	$ 79	$ 79	$ —	$ —
Other AFS debt securities	**31**	**—**	**31**	**—**	31	—	31	—
Derivative assets	**27**	**—**	**—**	**27**	16	—	—	16
Total assets	**155**	**97**	**31**	**27**	126	79	31	16
Derivative liabilities	**—**	**—**	**—**	**—**	(2)	(2)	—	—
Net assets	**$ 155**	**$ 97**	**$ 31**	**$ 27**	$ 124	$ 77	$ 31	$ 16

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Derivatives (net)	
	Years Ended December 31,	
(in millions)	**2017**	**2016**
Balance at beginning of period	**$ 16**	$ 7
Purchases, sales, issuances and settlements:		

Purchases	**52**	29
Settlements	**(43)**	(24)
Total gains included on the Consolidated Balance Sheet	**2**	4
Balance at end of period	**$ 27**	$ 16

PIEDMONT

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2017			December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 3**
Other trading equity securities	**$ —**	**$ —**	**$ —**	$ 4	$ 4	$ —
Other trading debt securities	**1**	**1**	**—**	1	1	—
Derivative assets	**2**	**2**	**—**	3	3	—
Total assets	**3**	**3**	**—**	8	8	—
Derivative liabilities	**(142)**	**—**	**(142)**	(187)	—	(187)
Net assets	**$ (139)**	**$ 3**	**$ (142)**	$ (179)	$ 8	$ (187)

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Derivatives (net)		
	Year Ended	**Two Months Ended**	**Year Ended**
(in millions)	**December 31, 2017**	**December 31, 2016**	**October 31, 2016**
Balance at beginning of period	**$ (187)**	$ (188)	$ —
Total gains (losses) and settlements	**45**	1	(188)
Balance at end of period	**$ (142)**	$ (187)	$ (188)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

The following tables include quantitative information about the Duke Energy Registrants' derivatives classified as Level 3.

	December 31, 2017			
Investment Type	**Fair Value (in millions)**	**Valuation Technique**	**Unobservable Input**	**Range**
Duke Energy Ohio				
FTRs	**$ 1**	RTO auction pricing	FTR price – per MWh	**$ 0.07 – $ 1.41**
Duke Energy Indiana				
FTRs	**27**	RTO auction pricing	FTR price – per MWh	**(0.77) – 7.44**
Piedmont				
Natural gas contracts	**(142)**	Discounted cash flow	Forward natural gas curves - price per MMBtu	**2.10 – 2.88**
Duke Energy				
Total Level 3 derivatives	**$ (114)**			

	December 31, 2016
	Fair Value

Investment Type	(in millions)	Valuation Technique	Unobservable Input	Range	
Duke Energy Ohio					
FTRs	$ 5	RTO auction pricing	FTR price – per MWh	0.77 –	3.52
Duke Energy Indiana					
FTRs	16	RTO auction pricing	FTR price – per MWh	(0.83) –	9.32
Piedmont					
Natural gas contracts	(187)	Discounted cash flow	Forward natural gas curves - price per MMBtu	2.31 –	4.18
Duke Energy					
Total Level 3 derivatives	$ (166)				

OTHER FAIR VALUE DISCLOSURES

The fair value and book value of long-term debt, including current maturities, is summarized in the following table. Estimates determined are not necessarily indicative of amounts that could have been settled in current markets. Fair value of long-term debt uses Level 2 measurements.

	December 31, 2017		**December 31, 2016**	
(in millions)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Duke Energy	**$ 52,279**	**$ 55,331**	$ 47,895	$ 49,161
Duke Energy Carolinas	**10,103**	**11,372**	9,603	10,494
Progress Energy	**17,837**	**20,000**	17,541	19,107
Duke Energy Progress	**7,357**	**7,992**	7,011	7,357
Duke Energy Florida	**7,095**	**7,953**	6,125	6,728
Duke Energy Ohio	**2,067**	**2,249**	1,884	2,020
Duke Energy Indiana	**3,783**	**4,464**	3,786	4,260
Piedmont	**2,037**	**2,209**	1,821	1,933

At both December 31, 2017, and December 31, 2016, fair value of cash and cash equivalents, accounts and notes receivable, accounts payable, notes payable and commercial paper and nonrecourse notes payable of VIEs are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

17. VARIABLE INTEREST ENTITIES

A VIE is an entity that is evaluated for consolidation using more than a simple analysis of voting control. The analysis to determine whether an entity is a VIE considers contracts with an entity, credit support for an entity, the adequacy of the equity investment of an entity and the relationship of voting power to the amount of equity invested in an entity. This analysis is performed either upon the creation of a legal entity or upon the occurrence of an event requiring reevaluation, such as a significant change in an entity’s assets or activities. A qualitative analysis of control determines the party that consolidates a VIE. This assessment is based on (i) what party has the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) what party has rights to receive benefits or is obligated to absorb losses that could potentially be significant to the VIE. The analysis of the party that consolidates a VIE is a continual reassessment.

CONSOLIDATED VIEs

The obligations of these VIEs discussed in the following paragraphs are nonrecourse to the Duke Energy Registrants. The registrants have no requirement to provide liquidity to, purchase assets of or guarantee performance of these VIEs unless noted in the following paragraphs.

No financial support was provided to any of the consolidated VIEs during the years ended December 31, 2017, 2016 and 2015, or is expected to be provided in the future, that was not previously contractually required.

Receivables Financing – DERF/DEPR/DEFR

Duke Energy Receivables Finance Company, LLC (DERF), Duke Energy Progress Receivables, LLC (DEPR) and Duke Energy Florida Receivables, LLC (DEFR) are bankruptcy remote, special purpose subsidiaries of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, respectively. DERF, DEPR and DEFR are wholly owned limited liability companies with separate legal existence from their parent companies and their assets are not generally available to creditors of their parent companies. On a revolving basis, DERF, DEPR and DEFR buy certain accounts receivable arising from the sale of electricity and related services from their parent companies.

DERF, DEPR and DEFR borrow amounts under credit facilities to buy these receivables. Borrowing availability from the credit facilities is limited to the amount of qualified receivables purchased. The sole source of funds to satisfy the related debt obligations is cash collections from the receivables. Amounts borrowed under the credit facilities are reflected on the Consolidated Balance Sheets as Long-Term Debt.

The most significant activity that impacts the economic performance of DERF, DEPR and DEFR are the decisions made to manage delinquent receivables. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida consolidate DERF, DEPR and DEFR, respectively, as they make those decisions.

Receivables Financing – CRC

CRC is a bankruptcy remote, special purpose entity indirectly owned by Duke Energy. On a revolving basis, CRC buys certain accounts receivable arising from the sale of electricity, natural gas and related services from Duke Energy Ohio and Duke Energy Indiana. CRC borrows amounts under a credit facility to buy the receivables from Duke Energy Ohio and Duke Energy Indiana. Borrowing availability from the credit facility is limited to the amount of qualified receivables sold to CRC. The sole source of funds to satisfy the related debt obligation is cash collections from the receivables. Amounts borrowed under the credit facility are reflected on Duke Energy's Consolidated Balance Sheets as Long-Term Debt.

The proceeds Duke Energy Ohio and Duke Energy Indiana receive from the sale of receivables to CRC are typically 75 percent cash and 25 percent in the form of a subordinated note from CRC. The subordinated note is a retained interest in the receivables sold. Depending on collection experience, additional equity infusions to CRC may be required by Duke Energy to maintain a minimum equity balance of $3 million.

CRC is considered a VIE because (i) equity capitalization is insufficient to support its operations, (ii) power to direct the activities that most significantly impact the economic performance of the entity are not performed by the equity holder and (iii) deficiencies in net worth of CRC are funded by Duke Energy. The most significant activities that impact the economic performance of CRC are decisions made to manage delinquent receivables. Duke Energy consolidates CRC as it makes these decisions. Neither Duke Energy Ohio nor Duke Energy Indiana consolidate CRC.

Receivables Financing – Credit Facilities

The following table outlines amounts and expiration dates of the credit facilities described above.

	Duke Energy			
		Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
	CRC	DERF	DEPR	DEFR
Expiration date	December 2020	December 2020	February 2019	April 2019
Credit facility amount (in millions)	$ 325	$ 450	$ 300	$ 225
Amounts borrowed at December 31, 2017	325	450	300	225
Amounts borrowed at December 31, 2016	325	425	300	225

Nuclear Asset-Recovery Bonds – DEFPF

Duke Energy Florida Project Finance, LLC (DEFPF) is a bankruptcy remote, wholly owned special purpose subsidiary of Duke Energy Florida. DEFPF was formed in 2016 for the sole purpose of issuing nuclear asset-recovery bonds to finance Duke Energy Florida's unrecovered regulatory asset related to Crystal River Unit 3.

In June 2016, DEFPF issued $1,294 million of senior secured bonds and used the proceeds to acquire nuclear asset-recovery property from Duke Energy Florida. The nuclear asset-recovery property acquired includes the right to impose, bill, collect and adjust a non-bypassable nuclear asset-recovery charge from all Duke Energy Florida retail customers until the bonds are paid in full and all financing costs have been recovered. The nuclear asset-recovery bonds are secured by the nuclear asset-recovery property and cash collections from the nuclear asset-recovery charges are the sole source of funds to satisfy the debt obligation. The bondholders have no recourse to Duke Energy Florida. For additional information see Notes 4 and 6.

DEFPF is considered a VIE primarily because the equity capitalization is insufficient to support its operations. Duke Energy Florida has the power to direct the significant activities of the VIE as described above and therefore Duke Energy Florida is considered the primary beneficiary and consolidates DEFPF.

The following table summarizes the impact of DEFPF on Duke Energy Florida's Consolidated Balance Sheets.

(in millions)	**December 31, 2017**	**December 31, 2016**
Receivables of VIEs	**$ 4**	$ 6
Regulatory Assets: Current	**51**	50
Current Assets: Other	**40**	53
Other Noncurrent Assets: Regulatory assets	**1,091**	1,142
Current Liabilities: Other	**10**	17
Current maturities of long-term debt	**53**	62
Long-Term Debt	**1,164**	1,217

Commercial Renewables

Certain of Duke Energy’s renewable energy facilities are VIEs due to Duke Energy issuing guarantees for debt service and operations and maintenance reserves in support of debt financings. Assets are restricted and cannot be pledged as collateral or sold to third parties without prior approval of debt holders. The activities that most significantly impact the economic performance of these renewable energy facilities were decisions associated with siting, negotiating PPAs, engineering, procurement and construction and decisions associated with ongoing operations and maintenance-related activities. Duke Energy consolidates the entities as it is responsible for all of these decisions.

The table below presents material balances reported on Duke Energy's Consolidated Balance Sheets related to renewables VIEs.

(in millions)	**December 31, 2017**	**December 31, 2016**
Current Assets: Other	**$ 174**	$ 223
Property, plant and equipment, cost	**3,923**	3,419
Accumulated depreciation and amortization	**(591)**	(453)
Current maturities of long-term debt	**170**	198
Long-Term Debt	**1,700**	1,097
Other Noncurrent Liabilities: Deferred income taxes	**(148)**	275
Other Noncurrent Liabilities: Other	**241**	252

NON-CONSOLIDATED VIEs

The following tables summarize the impact of non-consolidated VIEs on the Consolidated Balance Sheets.

	December 31, 2017					
	Duke Energy				Duke Energy	Duke Energy
(in millions)	Pipeline Investments	Commercial Renewables	Other VIEs(a)	Total	Ohio	Indiana
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 87	$ 106
Investments in equity method unconsolidated affiliates	697	180	42	919	—	—
Other noncurrent assets	17	—	—	17	—	—
Total assets	$ 714	$ 180	$ 42	$ 936	$ 87	$ 106
Taxes accrued	(29)	—	—	(29)	—	—
Other current liabilities	—	—	4	4	—	—
Deferred income taxes	42	—	—	42	—	—
Other noncurrent liabilities	—	—	12	12	—	—
Total liabilities	$ 13	$ —	$ 16	$ 29	$ —	$ —
Net assets	$ 701	$ 180	$ 26	$ 907	$ 87	$ 106

(a) Duke Energy holds a 50 percent equity interest in Duke-American Transmission Company, LLC (DATC). As of December 31, 2016, DATC was considered a VIE due to having insufficient equity to finance its own activities without subordinated financial support. However, DATC is no longer considered a VIE based on sufficient equity to finance its own activities, and, therefore, is no longer considered a VIE as of December 31, 2017. Duke Energy's investment in DATC was $46 million at December 31, 2017.

	December 31, 2016						
	Duke Energy				Duke Energy	Duke Energy	
(in millions)	Pipeline Investments	Commercial Renewables	Other	Total	Ohio	Indiana	Piedmont (a)
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 82	$ 101	$ —
Investments in equity method unconsolidated affiliates	487	174	90	751	—	—	139
Other noncurrent assets	12	—	—	12	—	—	—
Total assets	$ 499	$ 174	$ 90	$ 763	$ 82	$ 101	$ 139

Other current liabilities		—		—		3		3		—		—	—
Other noncurrent liabilities		—		—		13		13		—		—	4
Total liabilities	$	—	$	—	$	16	$	16	$	—	$	—	$ 4
Net assets	$	499	$	174	$	74	$	747	$	82	$	101	$ 135

(a) In April 2017, Piedmont transferred its non-consolidated VIE investments to a wholly owned subsidiary of Duke Energy. See Note 12 and the "Pipeline Investments" section below for additional detail.

The Duke Energy Registrants are not aware of any situations where the maximum exposure to loss significantly exceeds the carrying values shown above except for the power purchase agreement with OVEC, which is discussed below, and various guarantees, some of which are reflected in the table above as Other noncurrent liabilities. For more information on various guarantees, refer to Note 7.

Pipeline Investments

Duke Energy has investments in various joint ventures with pipeline projects currently under construction. These entities are considered VIEs due to having insufficient equity to finance their own activities without subordinated financial support. Duke Energy does not have the power to direct the activities that most significantly impact the economic performance, the obligation to absorb losses or the right to receive benefits of these VIEs and therefore does not consolidate these entities.

The table below presents Duke Energy's ownership interest and investment balance in in these joint ventures.

		Investment Amount (in millions)	
Entity Name	**Ownership Interest**	**December 31, 2017**	**December 31, 2016**
ACP	47%	**$ 397**	$ 265
Sabal Trail	7.5%	**219**	140
Constitution	24%	**81**	82
Total		**$ 697**	$ 487

Commercial Renewables

Duke Energy has investments in various renewable energy project entities. Some of these entities are VIEs due to Duke Energy issuing guarantees for debt service and operations and maintenance reserves in support of debt financings. Duke Energy does not consolidate these VIEs because power to direct and control key activities is shared jointly by Duke Energy and other owners.

Other VIEs

Duke Energy holds a 50 percent equity interest in Pioneer. Pioneer is considered a VIE due to having insufficient equity to finance their own activities without subordinated financial support. The activities that most significantly impact Pioneer's economic performance are decisions related to the development of new transmission facilities. The power to direct these activities is jointly and equally shared by Duke Energy and the other joint venture partner, American Electric Power, therefore Duke Energy does not consolidate Pioneer.

OVEC

Duke Energy Ohio’s 9 percent ownership interest in OVEC is considered a non-consolidated VIE due to having insufficient equity to finance their activities without subordinated financial support. As a counterparty to an inter-company power agreement (ICPA), Duke Energy Ohio has a contractual arrangement to buy power from OVEC’s power plants through June 2040 commensurate with its power participation ratio, which is equivalent to Duke Energy Ohio's ownership interest. Costs, including fuel, operating expenses, fixed costs, debt amortization, and interest expense are allocated to counterparties to the ICPA based on their power participation ratio. The value of the ICPA is subject to variability due to fluctuation in power prices and changes in OVEC's cost of business, including costs associated with its 2,256 MW of coal-fired generation capacity. Deterioration in the credit quality, or bankruptcy of one or more parties to the ICPA could increase the costs of OVEC. In addition, certain proposed environmental rulemaking could result in future increased cost allocations.

CRC

See discussion under Consolidated VIEs for additional information related to CRC.

Amounts included in Receivables from affiliated companies in the above table for Duke Energy Ohio and Duke Energy Indiana reflect their retained interest in receivables sold to CRC. These subordinated notes held by Duke Energy Ohio and Duke Energy Indiana are stated at fair value. Carrying values of retained interests are determined by allocating carrying value of the receivables between assets sold and interests retained based on relative fair value. The allocated bases of the subordinated notes are not materially different than their face value because (i) the receivables generally turnover in less than two months, (ii) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration and (iii) the equity in CRC is subordinate to all retained interests and thus would absorb losses first. The hypothetical effect on fair value of the retained interests assuming both a 10 percent and a 20 percent unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history. Interest accrues to Duke Energy Ohio and Duke Energy Indiana on the retained interests using the acceptable yield method. This method generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. An impairment charge is recorded against the carrying value of both retained interests and purchased beneficial interest whenever it is determined that an OTTI has occurred.

Key assumptions used in estimating fair value are detailed in the following table.

	Duke Energy Ohio		Duke Energy Indiana	
	2017	**2016**	**2017**	**2016**
Anticipated credit loss ratio	**0.5%**	0.5%	**0.3%**	0.3%
Discount rate	**2.1%**	1.5%	**2.1%**	1.5%
Receivable turnover rate	**13.5%**	13.3%	**10.7%**	10.6%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio		Duke Energy Indiana	
(in millions)	**2017**	**2016**	**2017**	**2016**
Receivables sold	**$ 273**	$ 267	**$ 312**	$ 306
Less: Retained interests	**87**	82	**106**	101
Net receivables sold	**$ 186**	$ 185	**$ 206**	$ 205

The following table shows sales and cash flows related to receivables sold.

	Duke Energy Ohio			Duke Energy Indiana		
	Years Ended December 31,			Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Sales						
Receivables sold	**$ 1,879**	$ 1,926	$ 1,963	**$ 2,711**	$ 2,635	$ 2,627
Loss recognized on sale	**10**	9	9	**12**	11	11
Cash Flows						
Cash proceeds from receivables sold	**1,865**	1,882	1,995	**2,694**	2,583	2,670
Collection fees received	**1**	1	1	**1**	1	1

Return received on retained interests	**3**	2	3	**7**	5	5

Cash flows from the sales of receivables are reflected within Cash Flows From Operating Activities on Duke Energy Ohio's and Duke Energy Indiana's Consolidated Statements of Cash Flows.

Collection fees received in connection with servicing transferred accounts receivable are included in Operation, maintenance and other on Duke Energy Ohio's and Duke Energy Indiana's Consolidated Statements of Operations and Comprehensive Income. The loss recognized on sales of receivables is calculated monthly by multiplying receivables sold during the month by the required discount. The required discount is derived monthly utilizing a three-year weighted average formula that considers charge-off history, late charge history and turnover history on the sold receivables, as well as a component for the time value of money. The discount rate, or component for the time value of money, is the prior month-end LIBOR plus a fixed rate of 1.00 percent.

18. COMMON STOCK

Basic Earnings Per Share (EPS) is computed by dividing net income attributable to Duke Energy common stockholders, as adjusted for distributed and undistributed earnings allocated to participating securities, by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to Duke Energy common stockholders, as adjusted for distributed and undistributed earnings allocated to participating securities, by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common shares, such as stock options and equity forward sale agreements, were exercised or settled. Duke Energy's participating securities are restricted stock units that are entitled to dividends declared on Duke Energy common stock during the restricted stock unit's vesting periods.

The following table presents Duke Energy's basic and diluted EPS calculations and reconciles the weighted average number of common stock outstanding to the diluted weighted average number of common stock outstanding.

	Years Ended December 31,		
(in millions, except per share amounts)	**2017**	**2016**	**2015**
Income from continuing operations attributable to Duke Energy common stockholders excluding impact of participating securities	**$ 3,059**	$ 2,567	$ 2,640
Weighted average shares outstanding – basic	**700**	691	694
Weighted average shares outstanding – diluted	**700**	691	694
Earnings per share from continuing operations attributable to Duke Energy common stockholders			
Basic	**$ 4.37**	$ 3.71	$ 3.80
Diluted	**$ 4.37**	$ 3.71	$ 3.80
Potentially dilutive items excluded from the calculation(a)	**2**	2	2
Dividends declared per common share	**$ 3.49**	$ 3.36	$ 3.24

(a) Performance stock awards were not included in the dilutive securities calculation because the performance measures related to the awards had not been met.

Equity Distribution Agreement

On February 20, 2018, Duke Energy filed a prospectus supplement and executed an Equity Distribution Agreement (the EDA) under which it may sell up to $1 billion of its common stock through an at-the-market offering program, including an equity forward sales component. The EDA was entered into with Wells Fargo Securities, LLC, Citigroup Global Markets Inc., and J.P. Morgan Securities LLC (the Agents). Under the terms of the EDA, Duke Energy may issue and sell, through either of the Agents, shares of common stock during the period ending September 23, 2019.

In addition to the issuance and sales of shares by Duke Energy through the Agents, Duke Energy may enter into Equity Forward Agreements with affiliates of the Agents as Forward Purchasers. There were no transactions under the EDA from the time of execution of the EDA to the filing of this document.

Stock Issuance

In March 2016, Duke Energy marketed an equity offering of 10.6 million shares of common stock. In lieu of issuing equity at the time of the offering, Duke Energy entered into Equity Forwards with Barclays. The Equity Forwards required Duke Energy to either physically settle the transactions by issuing 10.6 million shares, or net settle in whole or in part through the delivery or receipt of cash or shares.

On October 5, 2016, following the close of the Piedmont acquisition, Duke Energy physically settled the Equity Forwards in full by delivering 10.6 million shares of common stock in exchange for net cash proceeds of approximately $723 million. The net proceeds were used to finance a portion of the Piedmont acquisition. As a result of the acquisition, all of Piedmont's issued and outstanding stock became the issued and outstanding shares of a wholly owned subsidiary of Duke Energy. See Note 2 for additional information related to the Piedmont acquisition.

Accelerated Stock Repurchase Program

On April 6, 2015, Duke Energy entered into agreements with each of Goldman, Sachs & Co. and JPMorgan Chase Bank, National Association (the Dealers) to repurchase a total of $1.5 billion of Duke Energy common stock under an accelerated stock repurchase program (the ASR). Duke Energy made payments of $750 million to each of the Dealers and was delivered 16.6 million shares, with a total fair value of $1.275 billion, which represented approximately 85 percent of the total number of shares of Duke Energy common stock expected to be repurchased under the ASR. The company recorded the $1.5 billion payment as a reduction to common stock as of April 6, 2015. In June 2015, the Dealers delivered 3.2 million additional shares to Duke Energy to complete the ASR. Approximately 19.8 million shares, in total, were delivered to Duke Energy and retired under the ASR at an average price of $75.75 per share. The final number of shares repurchased was based upon the average of the daily volume weighted average stock prices of Duke Energy's common stock during the term of the program, less a discount.

19. SEVERANCE

As part of its strategic planning processes, Duke Energy implemented targeted cost savings initiatives during 2016 and 2015 aimed at reducing operations and maintenance expense. The initiatives included efforts to reduce costs through the standardization of processes and systems, leveraging technology and workforce optimization throughout the company.

During 2016, Duke Energy and Piedmont announced severance plans covering certain eligible employees whose employment will be involuntarily terminated without cause as a result of Duke Energy's acquisition of Piedmont. These reductions continue to be implemented and are a part of the synergies expected to be realized with the acquisition. Refer to Note 2 for additional information on the Piedmont acquisition.

Severance benefit costs for initiatives and plans discussed above were accrued for a total of approximately 100 employees in 2017, 600 employees in 2016 and 900 employees in 2015. The following table presents the direct and allocated severance and related expenses recorded by the Duke Energy Registrants. Amounts are included within Operation, maintenance and other on the Consolidated Statements of Operations.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont[(a)]
Year Ended December 31, 2017	**$ 15**	**$ 2**	**$ 2**	**$ 1**	**$ 1**	**$ —**	**$ 1**	**$ 9**
Year Ended December 31, 2016	118	39	40	23	17	3	7	
Year Ended December 31, 2015	142	93	36	28	8	2	6	

(a) Piedmont severance benefit costs were $3 million for the two months ended December 31, 2016, and $19 million for the year ended October 31, 2016. Piedmont did not record any severance benefit costs for the year ended October 31, 2015.

The table below presents the severance liability for past and ongoing severance plans including the plans described above. Amounts for Duke Energy Indiana and Duke Energy Ohio are not material.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Piedmont
Balance at December 31, 2016	$ 79	$ 13	$ 14	$ 6	$ 8	$ 20
Provision/Adjustments	**17**	**2**	**—**	**—**	**—**	**9**
Cash Reductions	**(77)**	**(10)**	**(12)**	**(5)**	**(8)**	**(24)**
Balance at December 31, 2017	**$ 19**	**$ 5**	**$ 2**	**$ 1**	**— $**	**5**

20. STOCK-BASED COMPENSATION

The Duke Energy Corporation 2015 Long-Term Incentive Plan (the 2015 Plan) provides for the grant of stock-based compensation awards to employees and outside directors. The 2015 Plan reserves 10 million shares of common stock for issuance. Duke Energy has historically issued new shares upon exercising or vesting of share-based awards. However, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards that are exercised or vest in the future. Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases.

The following table summarizes the total expense recognized by the Duke Energy Registrants, net of tax, for stock-based compensation.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Duke Energy	**$ 43**	$ 35	$ 38
Duke Energy Carolinas	**15**	12	14
Progress Energy	**16**	12	14
Duke Energy Progress	**10**	7	9
Duke Energy Florida	**6**	5	5
Duke Energy Ohio	**3**	2	2
Duke Energy Indiana	**4**	3	4
Piedmont(a)	**3**		

(a) See discussion below for information on Piedmont's pre-merger stock-based compensation plans.

Duke Energy's pretax stock-based compensation costs, the tax benefit associated with stock-based compensation expense and stock-based compensation costs capitalized are included in the following table.

	Years Ended December 31,		
(in millions)	2017	2016	2015
Restricted stock unit awards	**$ 41**	$ 36	$ 38
Performance awards	**27**	19	23
Pretax stock-based compensation cost	**$ 68**	$ 55	$ 61
Tax benefit associated with stock-based compensation expense	**$ 25**	$ 20	$ 23
Stock-based compensation costs capitalized	**4**	2	3

RESTRICTED STOCK UNIT AWARDS

Restricted stock unit (RSU) awards generally vest over periods from immediate to three years. Fair value amounts are based on the market price of Duke Energy's common stock on the grant date. The following table includes information related to restricted stock unit awards.

	Years Ended December 31,		
	2017	2016	2015
Shares awarded (in thousands)	**583**	684	524
Fair value (in millions)	**$ 47**	$ 52	$ 41

The following table summarizes information about restricted stock unit awards outstanding.

	Shares (in thousands)	Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2016	1,139	$ 76
Granted	**583**	**80**
Vested	**(553)**	**76**
Forfeited	**(48)**	**78**
Outstanding at December 31, 2017	**1,121**	**78**
Restricted stock unit awards expected to vest	**1,094**	**78**

The total grant date fair value of shares vested during the years ended December 31, 2017, 2016 and 2015 was $42 million, $38 million and $41 million, respectively. At December 31, 2017, Duke Energy had $29 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of twenty-three months.

PERFORMANCE AWARDS

Stock-based performance awards generally vest after three years if performance targets are met.

Performance awards granted in 2017, 2016 and 2015 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a predefined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards. The model uses three-year historical volatilities and correlations for all companies in the predefined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant are incorporated within the model. For performance awards granted in 2017, the model used a risk-free interest rate of 1.5 percent, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 17.2 percent based on Duke Energy's historical volatility over three years using daily stock prices.

In addition to TSR, performance awards granted in 2017 and 2016 contain a performance condition based on Duke Energy's cumulative adjusted EPS. Performance awards granted in 2017 also contain a performance condition based on the total incident case rate, one of our key employee safety metrics. The actual number of shares issued will range from zero to 200 percent of target shares depending on the level of performance achieved.

The following table includes information related to stock-based performance awards.

	Years Ended December 31,		
	2017	2016	2015
Shares granted assuming target performance (in thousands)	**461**	338	321
Fair value (in millions)	**$ 37**	$ 25	$ 26

The following table summarizes information about stock-based performance awards outstanding and assumes payout at the target level.

	Shares (in thousands)	Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2016	862	$ 75

Granted	**461**	**81**
Forfeited	**(258)**	**69**
Outstanding at December 31, 2017	**1,065**	**79**
Stock-based performance awards expected to vest	**1,034**	**79**

No performance awards vested during the year ended December 31, 2017. The total grant date fair value of shares vested during the years ended December 31, 2016 and 2015 was $25 million and $26 million, respectively. At December 31, 2017, Duke Energy had $34 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of twenty-three months.

STOCK OPTIONS

Stock options, when granted, have a maximum option term of 10 years and with an exercise price not less than the market price of Duke Energy's common stock on the grant date. There were no stock options granted or exercised during the year ended December 31, 2017. There were no stock options outstanding at December 31, 2017.

The following table summarizes additional information related to stock options exercised and granted.

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Intrinsic value of options exercised	$ 1	$ 5
Tax benefit related to options exercised	—	2
Cash received from options exercised	7	17

PIEDMONT

Prior to Duke Energy's acquisition of Piedmont, Piedmont had an incentive compensation plan that had a series of three-year performance and RSU awards for eligible officers and other participants. The Agreement and Plan of Merger (Merger Agreement) between Duke Energy and Piedmont provided for the conversion of the 2014-2016 and 2015-2017 performance awards and the nonvested 2016 RSU award into the right to receive $60 cash per share upon the close of the transaction. In December 2015, Piedmont's board of directors authorized the accelerated vesting, payment and taxation of the 2014-2016 and 2015-2017 performance awards, as well as the 2016 RSU award, at the election of the participant. Substantially all participants elected to accelerate the settlement of these awards. As a result of the settlement of these awards, 194 thousand shares of Piedmont shares were issued to participants, net of shares withheld for applicable federal and state income taxes, at a closing price of $56.85 and a fair value of $11 million. The 2016-2018 performance award cycle was approved subsequent to the Merger Agreement and was converted into a Duke Energy RSU award as discussed above at the consummation of the acquisition.

Piedmont's stock-based compensation costs and the tax benefit associated with stock-based compensation expense are included in the following table. Piedmont's stock-based compensation costs were not material for the two months ended December 31, 2016.

	Years Ended October 31,	
(in millions)	**2016**	**2015**
Pretax stock-based compensation cost	$ 16	$ 14
Tax benefit associated with stock-based compensation expense	6	4
Net of tax stock-based compensation cost	$ 10	$ 10

21. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT RETIREMENT PLANS

Duke Energy and certain subsidiaries maintain, and the Subsidiary Registrants participate in, qualified, non-contributory defined benefit retirement plans. The Duke Energy plans cover most employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits based upon a percentage of current eligible earnings, age or age and years of service and interest credits. Certain employees are eligible for benefits that use a final average earnings formula. Under these final average earnings formulas, a plan participant accumulates a retirement benefit equal to the sum of percentages of their (i) highest three-year, four-year, or five-year average earnings, (ii) highest three-year, four-year, or five-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), (iii) highest three-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains, and the Subsidiary Registrants participate in, non-qualified, non-contributory defined benefit retirement plans that cover certain executives. The qualified and non-qualified, non-contributory defined benefit plans are closed to new participants.

Duke Energy approved plan amendments to restructure its qualified non-contributory defined benefit retirement plans, effective January 1, 2018. The restructuring involved (i) the spin-off of the majority of inactive participants from two plans into a separate inactive plan and (ii) the merger of the active participant portions of such plans, along with a pension plan acquired as part of the Piedmont transaction, into a single active plan. Benefits offered to the plan participants remain unchanged except that the Piedmont plan's final average earnings formula was frozen as of December 31, 2017, and affected participants were moved into the active plan's cash balance formula. Actuarial gains and losses associated with the Inactive Plan will be amortized over the remaining life expectancy of the inactive participants. The longer amortization period is expected to lower Duke Energy's 2018 pretax qualified pension plan expense by approximately $33 million.

Duke Energy uses a December 31 measurement date for its defined benefit retirement plan assets and obligations.

Net periodic benefit costs disclosed in the tables below represent the cost of the respective benefit plan for the periods presented. However, portions of the net periodic benefit costs disclosed in the tables below have been capitalized as a component of property, plant and equipment. Amounts presented in the tables below for the Subsidiary Registrants represent the amounts of pension and other post-retirement benefit cost allocated by Duke Energy for employees of the Subsidiary Registrants. Additionally, the Subsidiary Registrants are allocated their proportionate share of pension and post-retirement benefit cost for employees of Duke Energy's shared services affiliate that provide support to the Subsidiary Registrants. These allocated amounts are included in the governance and shared service costs discussed in Note 13.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants. The following table includes information related to the Duke Energy Registrants' contributions to its qualified defined benefit pension plans.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont[a]
Anticipated Contributions:								
Total anticipated 2018 contributions	$ **148**	$ **46**	$ **45**	$ **25**	$ **20**	$ **—**	$ **8**	$ **7**
Contributions made January 2, 2018	141	46	45	25	20	—	8	—
Contributions to be made in 2018	$ **7**	$ **—**	$ **—**	$ **—**	$ **—**	$ **—**	$ **—**	$ **7**

Contributions Made:								
2017	**$ 19**	**$ —**	**$ —**	**$ —**	**$ —**	**$ 4**	**$ —**	**$ 11**
2016	155	43	43	24	20	5	9	
2015	302	91	83	42	40	8	19	

(a) Piedmont contributed $10 million to its U.S. qualified defined benefit pension plan during the two months ended December 31, 2016, and for each of the years ended October 31, 2016, and 2015, respectively.

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Service cost	**$ 159**	**$ 48**	**$ 45**	**$ 26**	**$ 19**	**$ 4**	**$ 9**	**$ 10**
Interest cost on projected benefit obligation	**328**	**79**	**100**	**47**	**53**	**18**	**26**	**14**
Expected return on plan assets	**(545)**	**(142)**	**(167)**	**(82)**	**(85)**	**(27)**	**(42)**	**(24)**
Amortization of actuarial loss	**146**	**31**	**52**	**23**	**29**	**5**	**12**	**11**
Amortization of prior service credit	**(24)**	**(8)**	**(3)**	**(2)**	**(1)**	**(1)**	**(2)**	**(2)**
Settlement charge	**12**	**—**	**—**	**—**	**—**	**—**	**—**	**12**
Other	**8**	**2**	**2**	**1**	**1**	**—**	**1**	**1**
Net periodic pension costs(a)(b)	**$ 84**	**$ 10**	**$ 29**	**$ 13**	**$ 16**	**$ (1)**	**$ 4**	**$ 22**

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 147	$ 48	$ 42	$ 24	$ 19	$ 4	$ 9
Interest cost on projected benefit obligation	335	86	106	49	55	19	28
Expected return on plan assets	(519)	(142)	(168)	(82)	(84)	(27)	(42)
Amortization of actuarial loss	134	33	51	23	29	4	11
Amortization of prior service (credit)	(17)	(8)	(3)	(2)	(1)	—	(1)
Settlement charge	3	—	—	—	—	—	—
Other	8	2	3	1	1	1	1
Net periodic pension costs(a)(b)	$ 91	$ 19	$ 31	$ 13	$ 19	$ 1	$ 6

	Year Ended December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 159	$ 50	$ 44	$ 23	$ 20	$ 4	$ 10
Interest cost on projected benefit obligation	324	83	104	48	54	18	27
Expected return on plan assets	(516)	(139)	(171)	(79)	(87)	(26)	(42)
Amortization of actuarial loss	166	39	65	33	31	7	13
Amortization of prior service (credit) cost	(15)	(7)	(3)	(2)	(1)	—	1
Other	8	2	3	1	1	—	1
Net periodic pension costs(a)(b)	$ 126	$ 28	$ 42	$ 24	$ 18	$ 3	$ 10

(a) Duke Energy amounts exclude $7 million, $8 million and $9 million for the years ended December 2017, 2016 and 2015, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $3 million, $4 million and $4 million for the years ended December 2017, 2016 and 2015, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

	Piedmont		
	Two Months Ended	Years Ended October 31,	
(in millions)	December 31, 2016	2016	2015
Service cost	$ 2	$ 11	$ 11
Interest cost on projected benefit obligation	2	9	12
Expected return on plan assets	(4)	(24)	(24)
Amortization of actuarial loss	2	8	9
Amortization of prior service credit	(1)	(2)	(2)
Settlement charge	3	—	—
Net periodic pension costs	$ 4	$ 2	$ 6

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont

Regulatory assets, net (decrease) increase	$ (212)	$ (70)	$ (49)	$ (37)	$ (11)	$ 9	$ (19)	$ (64)
Accumulated other comprehensive loss (income)								
Deferred income tax expense	$ —	—	3	—	—	—	—	—
Prior year service cost arising during the year	1	—	—	—	—	—	—	—
Amortization of prior year actuarial losses	(7)	—	(7)	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (6)	$ —	$ (4)	$ —	$ —	$ —	$ —	$ —

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Regulatory assets, net increase	$ 214	$ 4	$ 34	$ 18	$ 16	$ 2	$ 9
Accumulated other comprehensive (income) loss							
Deferred income tax expense	$ 4	$ —	$ —	$ —	$ —	$ —	$ —
Prior year service credit arising during the year	(2)	—	—	—	—	—	—
Amortization of prior year actuarial losses	(7)	—	(1)	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (5)	$ —	$ (1)	$ —	$ —	$ —	$ —

Piedmont's regulatory asset net increase was $34 million, $35 million and $20 million for the two months ended December 31, 2016, and for the years ended October 31, 2016, and 2015, respectively.

Reconciliation of Funded Status to Net Amount Recognized

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 8,131	$ 1,952	$ 2,512	$ 1,158	$ 1,323	$ 447	$ 658	$ 344
Service cost	159	48	45	26	19	4	9	10
Interest cost	328	79	100	47	53	18	26	14
Actuarial loss	455	68	158	57	99	35	26	38
Transfers	—	27	(32)	(2)	(15)	12	—	—
Plan amendments	(61)	—	—	—	—		—	(61)
Benefits paid	(537)	(145)	(146)	(75)	(69)	(37)	(50)	(5)
Benefits paid - settlements	(27)	—	—	—	—	—	—	(27)
Obligation at measurement date	$ 8,448	$ 2,029	$ 2,637	$ 1,211	$ 1,410	$ 479	$ 669	$ 313
Accumulated Benefit Obligation at measurement date	$ 8,369	$ 2,029	$ 2,601	$ 1,211	$ 1,375	$ 468	$ 652	$ 313
Change in Fair Value of Plan Assets								

Plan assets at prior measurement date	**$ 8,531**	**$ 2,225**	**$ 2,675**	**$ 1,290**	**$ 1,352**	**$ 428**	**$ 657**	**$ 346**
Employer contributions	**19**	**—**	**—**	**—**	**—**	**4**	**—**	**11**
Actual return on plan assets	**1,017**	**265**	**317**	**153**	**161**	**51**	**77**	**43**
Benefits paid	**(537)**	**(145)**	**(146)**	**(75)**	**(69)**	**(37)**	**(50)**	**(5)**
Benefits paid - settlements	**(27)**	**—**	**—**	**—**	**—**	**—**	**—**	**(27)**
Transfers	**—**	**27**	**(32)**	**(2)**	**(15)**	**12**	**—**	**—**
Plan assets at measurement date	**$ 9,003**	**$ 2,372**	**$ 2,814**	**$ 1,366**	**$ 1,429**	**$ 458**	**$ 684**	**$ 368**
Funded status of plan	**$ 555**	**$ 343**	**$ 177**	**$ 155**	**$ 19**	**$ (21)**	**$ 15**	**$ 55**

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Change in Projected Benefit Obligation							
Obligation at prior measurement date	$ 7,727	$ 1,995	$ 2,451	$ 1,143	$ 1,276	$ 453	$ 649
Obligation assumed from acquisition	352	—	—	—	—	—	—
Service cost	147	48	42	24	19	4	9
Interest cost	335	86	106	49	55	19	28
Actuarial loss	307	46	111	52	57	13	41
Transfers	—	14	(3)	(3)	—	(3)	—
Plan amendments	(52)	(3)	—	—	—	(3)	(15)
Benefits paid	(679)	(234)	(195)	(107)	(84)	(36)	(54)
Impact of settlements	(6)	—	—	—	—	—	—
Obligation at measurement date	$ 8,131	$ 1,952	$ 2,512	$ 1,158	$ 1,323	$ 447	$ 658
Accumulated Benefit Obligation at measurement date	$ 8,006	$ 1,952	$ 2,479	$ 1,158	$ 1,290	$ 436	$ 649
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	$ 8,136	$ 2,243	$ 2,640	$ 1,284	$ 1,321	$ 433	$ 655
Assets received from acquisition	343	—	—	—	—	—	—
Employer contributions	155	43	43	24	20	5	9
Actual return on plan assets	582	159	190	92	95	29	47
Benefits paid	(679)	(234)	(195)	(107)	(84)	(36)	(54)
Impact of settlements	(6)	—	—	—	—	—	—
Transfers	—	14	(3)	(3)	—	(3)	—

Plan assets at measurement date	$ 8,531	$ 2,225	$ 2,675	$ 1,290	$ 1,352	$ 428	$ 657
Funded status of plan	$ 400	$ 273	$ 163	$ 132	$ 29	$ (19)	$ (1)

	Piedmont	
	Two Months Ended	Years Ended
(in millions)	**December 31, 2016**	**October 31, 2016**
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$ 352	$ 312
Service cost	2	11
Interest cost	2	9
Actuarial gain	(5)	34
Benefits paid	(1)	(14)
Impact of settlements	(6)	—
Obligation at measurement date	$ 344	$ 352
Accumulated Benefit Obligation at measurement date	$ 289	$ 296
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ 343	$ 329
Employer contributions	10	10
Actual return on plan assets	—	18
Benefits paid	(1)	(14)
Impact of settlements	(6)	—
Plan assets at measurement date	$ 346	$ 343
Funded status of plan	$ 2	$ (9)

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Prefunded pension[(a)]	$ 680	$ 343	$ 245	$ 155	$ 87	$ 8	$ 16	$ 55
Noncurrent pension liability[(b)]	$ 125	$ —	$ 68	$ —	$ 68	$ 29	$ 1	$ —
Net asset (liability) recognized	$ 555	$ 343	$ 177	$ 155	$ 19	$ (21)	$ 15	$ 55
Regulatory assets	$ 1,886	$ 406	$ 756	$ 341	$ 415	$ 90	$ 152	$ 73
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (41)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(5)	—	—	—	—	—	—	—
Net actuarial loss	116	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 70	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 132	$ 29	$ 44	$ 21	$ 23	$ 5	$ 7	$ 11
Unrecognized prior service credit	(32)	(8)	(3)	(2)	(1)	—	(2)	(9)

	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Prefunded pension[(a)]	$ 518	$ 273	$ 225	$ 132	$ 91	$ 6	$ —	3
Noncurrent pension liability[(b)]	$ 118	$ —	$ 62	$ —	$ 62	$ 25	$ 1	—
Net asset recognized	$ 400	$ 273	$ 163	$ 132	$ 29	$ (19)	$ (1)	$ 3
Regulatory assets	$ 2,098	$ 476	$ 805	$ 378	$ 426	$ 81	$ 171	$ 137
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (41)	$ —	$ (6)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(6)	—	—	—	—	—	—	—
Net actuarial loss	123	—	16	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 76	$ —	$ 10	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 147	$ 31	$ 52	$ 23	$ 29	$ 5	$ 8	$ 13
Unrecognized prior service credit	$ (24)	$ (8)	$ (3)	$ (2)	$ (1)	$ —	$ (2)	$ (2)

(a) Included in Other within Other Noncurrent Assets on the Consolidated Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Consolidated Balance Sheets.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	December 31, 2017			
(in millions)	Duke Energy	Progress Energy	Duke Energy Florida	Duke Energy Ohio
Projected benefit obligation	**$ 1,386**	**$ 718**	**$ 718**	**$ 337**
Accumulated benefit obligation	**1,326**	**683**	**683**	**326**
Fair value of plan assets	**1,260**	**650**	**650**	**308**

	December 31, 2016	
	Duke	Duke

(in millions)	Duke Energy	Progress Energy	Energy Florida	Energy Ohio
Projected benefit obligation	$ 1,299	$ 665	$ 665	$ 311
Accumulated benefit obligation	1,239	633	633	299
Fair value of plan assets	1,182	604	604	286

Assumptions Used for Pension Benefits Accounting

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

The average remaining service period of active covered employees is 13 years for Duke Energy and Duke Energy Progress, 12 years for Duke Energy Carolinas, Progress Energy, and Duke Energy Florida, 14 years for Duke Energy Ohio and Duke Energy Indiana, and nine years for Piedmont.

The following tables present the assumptions or range of assumptions used for pension benefit accounting.

	December 31,		
	2017	2016	2015
Benefit Obligations			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.00% – 4.50%	4.00% – 4.40%
Net Periodic Benefit Cost			
Discount rate	**4.10%**	4.40%	4.10%
Salary increase	**4.00% – 4.50%**	4.00% – 4.40%	4.00% – 4.40%
Expected long-term rate of return on plan assets	**6.50% – 6.75%**	6.50% – 6.75%	6.50%

	Piedmont		
	Two Months Ended	Years Ended October 31,	
	December 31, 2016	2016	2015
Benefit Obligations			
Discount rate	4.10%	3.80%	4.34%
Salary increase	4.50%	4.05%	4.07%
Net Periodic Benefit Cost			
Discount rate	3.80%	4.34%	4.13%
Salary increase	4.05%	4.07%	3.68%
Expected long-term rate of return on plan assets	6.75%	7.25%	7.50%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2018	$ 642	$ 185	$ 161	$ 85	$ 75	$ 36	$ 47	$ 29
2019	644	185	164	86	77	36	46	26
2020	661	195	172	90	80	36	44	24
2021	666	194	175	93	81	37	44	24
2022	672	197	176	92	83	36	44	23
2023-2027	3,099	865	888	449	435	166	210	103

NON-QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	**$ 2**	**$ 1**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Interest cost on projected benefit obligation	**13**	**1**	**5**	**1**	**2**	**—**	**—**	**—**
Amortization of actuarial loss	**8**	**—**	**2**	**1**	**1**	**—**	**—**	**—**
Amortization of prior service credit	**(2)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net periodic pension costs	**$ 21**	**$ 2**	**$ 7**	**$ 2**	**$ 3**	**$ —**	**$ —**	**$ —**

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 2	$ —	$ —	$ —	$ —	$ —	$ —
Interest cost on projected benefit obligation	14	1	5	1	2	—	—
Amortization of actuarial loss	8	1	1	1	1	—	—
Amortization of prior service credit	(1)	—	—	—	—	—	—
Net periodic pension costs	$ 23	$ 2	$ 6	$ 2	$ 3	$ —	$ —

	Year Ended December 31, 2015						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 3	$ —	$ 1	$ —	$ —	$ —	$ —
Interest cost on projected benefit obligation	13	1	4	1	2	—	—
Amortization of actuarial loss	6	—	2	1	2	—	1
Amortization of prior service credit	(1)	—	(1)	—	—	—	—
Net periodic pension costs	$ 21	$ 1	$ 6	$ 2	$ 4	$ —	$ 1

	Piedmont	
	Years Ended October 31,	
(in millions)	**2016**	**2015**
Amortization of prior service cost	$ —	$ 1
Settlement charge	1	—
Net periodic pension costs	$ 1	$ 1

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Regulatory assets, net (decrease) increase	**$ 5**	**$ (1)**	**$ 3**	**$ 1**	**$ 2**	**$ —**	**$ —**	**$ —**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ (1)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Actuarial loss arising during the year	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive loss (income)	**$ 1**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Regulatory assets, net (decrease) increase	$ (3)	$ (2)	$ 2	$ 1	$ 1	$ —	$ (1)
Accumulated other comprehensive (income) loss							
Prior service credit arising during the year	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —
Actuarial gains arising during the year	1	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	Year Ended December 31, 2017							
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Service cost	2	1	—	—	—	—	—	—
Interest cost	13	1	5	1	2	—	—	—
Actuarial losses (gains)	15	—	5	4	2	—	—	—
Benefits paid	(31)	(2)	(8)	(3)	(3)	—	—	—
Obligation at measurement date	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Accumulated Benefit Obligation at measurement date	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Change in Fair Value of Plan Assets								
Benefits paid	$ (31)	$ (2)	$ (8)	$ (3)	$ (3)	$ —	$ —	$ —
Employer contributions	31	2	8	3	3	—	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
	Year Ended December 31, 2016						
Change in Projected Benefit Obligation							
Obligation at prior measurement date	$ 341	$ 16	$ 112	$ 33	$ 46	$ 4	$ 5
Obligation assumed from acquisition	5	—	—	—	—	—	—
Service cost	2	—	—	—	—	—	—
Interest cost	14	1	5	1	2	—	—
Actuarial losses (gains)	4	(1)	5	2	1	—	(2)
Plan amendments	(2)	—	—	—	—	—	
Benefits paid	(32)	(2)	(8)	(3)	(3)	—	—
Obligation at measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3
Accumulated Benefit Obligation at measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3
Change in Fair Value of Plan Assets							
Benefits paid	$ (32)	$ (2)	$ (8)	$ (3)	(3)	—	—
Employer contributions	32	2	8	3	3	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(in millions)	Piedmont Two Months Ended December 31, 2016	Piedmont Years Ended October 31, 2016
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$ 5	$ 6
Actuarial gain	(1)	—
Impact of settlements	—	(1)
Obligation at measurement date	$ 4	$ 5
Accumulated Benefit Obligation at measurement date	$ —	$ 5
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ —	$ 1
Impact of settlements	—	(1)
Plan assets at measurement date	$ —	$ —

Amounts Recognized in the Consolidated Balance Sheets

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2017							
Current pension liability[a]	$ 23	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
Noncurrent pension liability[b]	308	12	108	32	44	4	3	4
Total accrued pension liability	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Regulatory assets	$ 78	$ 4	$ 21	$ 8	$ 13	$ 1	$ —	$ 1
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (4)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	12	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 7	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 8	$ —	$ 2	$ 1	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(2)	—	—	—	—	—	—	—

December 31, 2016

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current pension liability[a]	$ 28	$ 2	$ 8	$ 2	$ 3	$ —	$ —	$ —
Noncurrent pension liability[b]	304	12	106	31	43	4	3	4
Total accrued pension liability	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Regulatory assets	$ 73	$ 5	$ 18	$ 7	$ 11	$ 1	$ —	$ 1
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (3)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	10	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 6	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 7	$ —	$ 2	$ 1	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(a) Included in Other within Current Liabilities on the Consolidated Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Consolidated Balance Sheets.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Projected benefit obligation	**$ 331**	**$ 14**	**$ 116**	**$ 35**	**$ 47**	**$ 4**	**$ 3**	**$ 4**
Accumulated benefit obligation	**331**	**14**	**116**	**35**	**47**	**4**	**3**	**4**

	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Projected benefit obligation	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Accumulated benefit obligation	332	14	114	33	46	4	3	4

Assumptions Used for Pension Benefits Accounting

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

The average remaining service period of active covered employees is 11 years for Duke Energy and Duke Energy Progress, 14 years for Progress Energy, 15 years for Duke Energy Florida, eight years for Duke Energy Carolinas, Duke Energy Ohio, and Duke Energy Indiana, and nine years for Piedmont. The following tables present the assumptions used for pension benefit accounting.

	December 31,		
	2017	**2016**	**2015**
Benefit Obligations			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.40%	4.40%
Net Periodic Benefit Cost			
Discount rate	**4.10%**	4.40%	4.10%
Salary increase	**4.40%**	4.40%	4.40%

	Piedmont		
	Two Months Ended	**Years Ended October 31,**	
	December 31, 2016	**2016**	**2015**
Benefit Obligations			
Discount rate	4.10%	3.80%	3.85%
Net Periodic Benefit Cost			
Discount rate	3.80%	3.85%	3.69%

Expected Benefit Payments

(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Years ending December 31,								
2018	$ 23	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
2019	21	1	8	2	3	—	—	—
2020	21	1	8	2	3	—	—	—
2021	22	1	8	2	3	—	—	—
2022	25	1	8	2	3	—	—	—
2023-2027	117	6	36	11	15	1	1	2

OTHER POST-RETIREMENT BENEFIT PLANS

Duke Energy provides, and the Subsidiary Registrants participate in, some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The health care benefits include medical, dental and prescription drug coverage and are subject to certain limitations, such as deductibles and copayments.

Duke Energy did not make any pre-funding contributions to its other post-retirement benefit plans during the years ended December 31, 2017, 2016 or 2015.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 4	$ 1	$ —	$ —	$ —	$ —	$ —	$ 1
Interest cost on accumulated post-retirement benefit obligation	34	8	13	7	6	1	3	1
Expected return on plan assets	(14)	(8)	—	—	—	—	(1)	(2)
Amortization of actuarial loss (gain)	10	(2)	21	12	9	(2)	(1)	1
Amortization of prior service credit	(115)	(10)	(84)	(54)	(30)	—	(1)	—
Curtailment credit (c)	$ (30)	$ (4)	$ (16)	$ —	$ (16)	$ (2)	$ (2)	$ —
Net periodic post-retirement benefit costs(a)(b)	$ (111)	$ (15)	$ (66)	$ (35)	$ (31)	$ (3)	$ (2)	$ 1

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 3	$ 1	$ 1	$ —	$ 1	$ —	$ —
Interest cost on accumulated post-retirement benefit obligation	35	8	15	8	7	1	4
Expected return on plan assets	(12)	(8)	—	—	—	—	(1)
Amortization of actuarial loss (gain)	6	(3)	22	13	9	(2)	(1)
Amortization of prior service credit	(141)	(14)	(103)	(68)	(35)	—	(1)
Net periodic post-retirement benefit costs(a)(b)	$ (109)	$ (16)	$ (65)	$ (47)	$ (18)	$ (1)	$ 1

	Year Ended December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 6	$ 1	$ 1	$ 1	$ 1	$ —	$ 1

Interest cost on accumulated post-retirement benefit obligation	36	9	15	8	7	2	4
Expected return on plan assets	(13)	(8)	—	—	—	(1)	(1)
Amortization of actuarial loss (gain)	16	(2)	28	18	10	(2)	(2)
Amortization of prior service credit	(140)	(14)	(102)	(68)	(35)	—	—
Net periodic post-retirement benefit costs(a)(b)	$ (95)	$ (14)	$ (58)	$ (41)	$ (17)	$ (1)	$ 2

(a) Duke Energy amounts exclude $7 million, $8 million and $10 million for the years ended December 2017, 2016 and 2015, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $2 million, $2 million and $3 million for the years ended December 2017, 2016 and 2015, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(c) Curtailment credit resulted from a reduction in average future service of plan participants due to a plan amendment.

	Piedmont	
	Years Ended October 31,	
(in millions)	2016	2015
Service cost	$ 1	$ 1
Interest cost on projected benefit obligation	1	2
Expected return on plan assets	(2)	(2)
Amortization of actuarial loss	1	—
Net periodic pension costs	$ 1	$ 1

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net increase (decrease)	$ 71	$ —	$ 81	$ 42	$ 39	$ —	$ (5)	$ (11)

Regulatory liabilities, net increase (decrease)	**$ (27)**	**$ (2)**	**$ —**	**$ —**	**$ —**	**$ (3)**	**$ (7)**	**$ —**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ (1)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Amortization of prior year prior service credit	**3**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ 2**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Regulatory assets, net increase (decrease)	$ 53	$ —	$ 47	$ 38	$ 9	$ —	$ (6)
Regulatory liabilities, net increase (decrease)	$ (114)	$ (22)	$ (51)	$ (25)	$ (26)	$ (2)	$ (12)
Accumulated other comprehensive (income) loss							
Deferred income tax benefit	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —
Actuarial losses arising during the year	3	—	—	—	—	—	—
Amortization of prior year prior service credit	1	—	1	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 2	$ —	$ 1	$ —	$ —	$ —	$ —

Piedmont's regulatory assets net decreased $1 million for the two months ended December 31, 2016, and increased $2 million and $1 million for the years ended October 31, 2016, and 2015, respectively.

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	**$ 868**	**$ 201**	**$ 357**	**$ 191**	**$ 164**	**$ 32**	**$ 83**	**$ 39**
Service cost	**4**	**1**	**—**	**—**	**—**	**—**	**—**	**1**
Interest cost	**34**	**8**	**13**	**7**	**6**	**1**	**3**	**1**

Plan participants' contributions	**17**	**3**	**6**	**3**	**3**	**1**	**2**	**—**
Actuarial (gains) losses	**4**	**(3)**	**4**	**1**	**3**	**—**	**3**	**1**
Transfers	**—**	**2**	**(1)**	**—**	**(1)**	**1**	**—**	**—**
Plan amendments	**(28)**	**(5)**	**(3)**	**(1)**	**(2)**	**(2)**	**(2)**	**(9)**
Benefits paid	**(86)**	**(18)**	**(34)**	**(17)**	**(17)**	**(3)**	**(11)**	**(1)**
Accumulated post-retirement benefit obligation at measurement date	**$ 813**	**$ 189**	**$ 342**	**$ 184**	**$ 156**	**$ 30**	**$ 78**	**$ 32**
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	**$ 244**	**$ 137**	**$ 1**	**$ —**	**$ —**	**$ 7**	**$ 22**	**$ 29**
Actual return on plan assets	**25**	**15**	**1**	**—**	**—**	**2**	**1**	**3**
Benefits paid	**(86)**	**(18)**	**(34)**	**(17)**	**(17)**	**(3)**	**(11)**	**(1)**
Employer contributions (reimbursements)	**25**	**(4)**	**26**	**14**	**14**	**—**	**(3)**	**—**
Plan participants' contributions	**17**	**3**	**6**	**3**	**3**	**1**	**2**	**—**
Plan assets at measurement date	**$ 225**	**$ 133**	**$ —**	**$ —**	**$ —**	**$ 7**	**$ 11**	**$ 31**

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Change in Projected Benefit Obligation							
Accumulated post-retirement benefit obligation at prior measurement date	$ 828	$ 200	$ 354	$ 188	$ 164	$ 35	$ 87
Obligation assumed from acquisition	39	—	—	—	—	—	—
Service cost	3	1	1	—	1	—	—
Interest cost	35	8	15	8	7	1	4
Plan participants' contributions	19	3	7	4	3	1	2
Actuarial (gains) losses	33	5	16	8	8	—	3
Transfers	—	1	—	—	—	—	—
Plan amendments	(1)	—	—	—	—	(1)	—

Benefits paid	(88)	(17)	(36)	(17)	(19)	(4)	(13)
Accumulated post-retirement benefit obligation at measurement date	$ 868	$ 201	$ 357	$ 191	$ 164	$ 32	$ 83
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	$ 208	$ 134	$ —	$ —	$ 1	$ 8	$ 19
Assets received from acquisition	29	—	—	—	—	—	—
Actual return on plan assets	14	8	1	—	—	1	2
Benefits paid	(88)	(17)	(36)	(17)	(19)	(4)	(13)
Employer contributions	62	9	29	13	15	1	12
Plan participants' contributions	19	3	7	4	3	1	2
Plan assets at measurement date	$ 244	$ 137	$ 1	$ —	$ —	$ 7	$ 22

	Piedmont	
	Two Months Ended	Years Ended
(in millions)	**December 31, 2016**	**October 31, 2016**
Change in Projected Benefit Obligation		
Accumulated post-retirement benefit obligation at prior measurement date	$ 39	$ 38
Service cost	—	1
Interest cost	—	1
Actuarial gain	—	2
Benefits paid	—	(3)
Accumulated post-retirement benefit obligation at measurement date	$ 39	$ 39
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ 29	$ 28
Employer contributions	—	3
Actual return on plan assets	—	1
Benefits paid	—	(3)
Plan assets at measurement date	$ 29	$ 29

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2017

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current post-retirement liability[a]	$ 36	$ —	$ 29	$ 15	$ 14	$ 2	$ —	$ —
Noncurrent post-retirement liability[b]	552	56	313	169	142	21	67	1
Total accrued post-retirement liability	$ 588	$ 56	$ 342	$ 184	$ 156	$ 23	$ 67	$ 1
Regulatory assets	$ 125	$ —	$ 129	$ 80	$ 49	$ —	$ 46	$ (4)
Regulatory liabilities	$ 147	$ 44	$ —	$ —	$ —	$ 16	$ 64	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 4	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(2)	—	—	—	—	—	—	—
Net actuarial gain	(10)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (8)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 5	$ 3	$ 1	$ —	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(19)	(5)	(7)	(1)	(6)	(1)	(1)	(2)

	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current post-retirement liability[a]	$ 38	$ —	$ 31	$ 17	$ 15	$ 2	$ —	$ —
Noncurrent post-retirement liability[b]	586	64	325	174	149	23	63	10
Total accrued post-retirement liability	$ 624	$ 64	$ 356	$ 191	$ 164	$ 25	$ 63	$ 10

Regulatory assets	$ 54	$ —	$ 48	$ 38	$ 10	$ —	$ 51	$ 7
Regulatory liabilities	$ 174	$ 46	$ —	$ —	$ —	$ 19	$ 71	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 5	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(5)	—	—	—	—	—	—	—
Net actuarial gain	(10)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (10)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss (gain)	$ 10	$ (2)	$ 21	$ 12	$ 9	$ (2)	$ (6)	$ —
Unrecognized prior service credit	(115)	(10)	(85)	(55)	(30)	—	(1)	—

(a) Included in Other within Current Liabilities on the Consolidated Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Consolidated Balance Sheets.

Assumptions Used for Other Post-Retirement Benefits Accounting

The discount rate used to determine the current year other post-retirement benefits obligation and following year's other post-retirement benefits expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected. The average remaining service period of active covered employees is nine years for Duke Energy, eight years for Duke Energy Carolinas, seven years for Duke Energy Florida, Duke Energy Ohio, and Piedmont, and six years for Progress Energy, Duke Energy Progress, and Duke Energy Indiana.

The following tables present the assumptions used for other post-retirement benefits accounting.

	December 31,		
	2017	**2016**	**2015**
Benefit Obligations			
Discount rate	**3.60%**	4.10%	4.40%
Net Periodic Benefit Cost			
Discount rate	**4.10%**	4.40%	4.10%
Expected long-term rate of return on plan assets	**6.50%**	6.50%	6.50%
Assumed tax rate	**35%**	35%	35%

	Piedmont		
	Two Months Ended	**Years Ended October 31,**	
	December 31, 2016	**2016**	**2015**
Benefit Obligations			
Discount rate	4.10%	3.80%	4.38%
Net Periodic Benefit Cost			
Discount rate	3.80%	4.38%	4.03%

Expected long-term rate of return on plan assets	6.75%	7.25%	7.50%

Assumed Health Care Cost Trend Rate

	December 31,	
	2017	**2016**
Health care cost trend rate assumed for next year	**7.00%**	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75%**	4.75%
Year that rate reaches ultimate trend	**2024**	2023

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
1-Percentage Point Increase								
Effect on total service and interest costs	**$ 1**	**$ —**	**$ 1**	**$ 1**	**$ —**	**$ —**	**$ —**	**$ —**
Effect on post-retirement benefit obligation	**27**	**6**	**11**	**6**	**5**	**1**	**3**	**1**
1-Percentage Point Decrease								
Effect on total service and interest costs	**(1)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Effect on post-retirement benefit obligation	**(24)**	**(6)**	**(10)**	**(5)**	**(5)**	**(1)**	**(2)**	**(1)**

Expected Benefit Payments

(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Years ending December 31,								
2018	$ 78	$ 17	$ 30	$ 16	$ 14	$ 3	$ 9	$ 2
2019	76	17	29	15	14	3	9	2
2020	73	17	29	15	14	3	8	2
2021	71	17	28	15	13	3	7	3
2022	68	17	27	14	13	3	7	3
2023 – 2027	290	70	117	63	54	12	29	13

PLAN ASSETS

Description and Allocations

Duke Energy Master Retirement Trust

Assets for both the qualified pension and other post-retirement benefits are maintained in the Duke Energy Master Retirement Trust. Qualified pension and other post-retirement assets related to Piedmont were transferred into the Duke Energy Master Retirement Trust during 2017. Approximately 98 percent of the Duke Energy Master Retirement Trust assets were allocated to qualified pension plans and approximately 2 percent were allocated to other post-retirement plans (comprised of 401(h) accounts), as of December 31, 2017, and 2016. The investment objective of the Duke Energy Master Retirement Trust is to achieve reasonable returns, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants.

As of December 31, 2017, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.50 percent. The expected long-term rate of return was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers, where applicable. The asset allocation targets were set after considering the investment objective and the risk profile. Equity securities are held for their higher expected returns. Debt securities are primarily held to hedge the qualified pension plan liability. Hedge funds, real estate and other global securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the impact of individual managers or investments.

In 2013, Duke Energy adopted a de-risking investment strategy for the Duke Energy Master Retirement Trust. As the funded status of the pension plans increase, the targeted allocation to fixed-income assets may be increased to better manage Duke Energy's pension liability and reduce funded status volatility. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The Duke Energy Master Retirement Trust is authorized to engage in the lending of certain plan assets. Securities lending is an investment management enhancement that utilizes certain existing securities of the Duke Energy Master Retirement Trust to earn additional income. Securities lending involves the loaning of securities to approved parties. In return for the loaned securities, the Duke Energy Master Retirement Trust receives collateral in the form of cash and securities as a safeguard against possible default of any borrower on the return of the loan under terms that permit the Duke Energy Master Retirement Trust to sell the securities. The Duke Energy Master Retirement Trust mitigates credit risk associated with securities lending arrangements by monitoring the fair value of the securities loaned, with additional collateral obtained or refunded as necessary. The fair value of securities on loan was approximately $195 million and $156 million at December 31, 2017, and 2016, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2017, and 2016, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2017, 2016 and 2015, respectively.

Qualified pension and other post-retirement benefits for the Subsidiary Registrants are derived from the Duke Energy Master Retirement Trust, as such, each are allocated their proportionate share of the assets discussed below.

The following table includes the target asset allocations by asset class at December 31, 2017, and the actual asset allocations for the Duke Energy Master Retirement Trust.

	Target Allocation	Actual Allocation at December 31, 2017	2016[(a)]
U.S. equity securities	10%	**11%**	11%
Non-U.S. equity securities	8%	**8%**	8%
Global equity securities	10%	**10%**	10%
Global private equity securities	3%	**2%**	2%
Debt securities	63%	**63%**	63%
Hedge funds	2%	**2%**	2%
Real estate and cash	2%	**2%**	2%
Other global securities	2%	**2%**	2%
Total	100%	**100%**	100%

(a) Excludes Piedmont Pension Assets, which had a targeted asset allocation of 60 percent return-seeking and 40 percent liability hedging fixed-income. Actual asset allocations were 61 percent return-seeking and 39 percent liability hedging fixed-income at December 31, 2016.

Other post-retirement assets

Duke Energy's other post-retirement assets are comprised of Voluntary Employees' Beneficiary Association (VEBA) trusts and 401(h) accounts held within the Duke Energy Master Retirement Trust. Duke Energy's investment objective is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants.

The following table presents target and actual asset allocations for the VEBA trusts at December 31, 2017.

	Target Allocation	Actual Allocation at December 31, 2017	Actual Allocation at December 31, 2016
U.S. equity securities	32%	**41%**	39%
Non-US equity securities	6%	**8%**	—%
Real estate	2%	**2%**	2%
Debt securities	45%	**36%**	37%
Cash	15%	**13%**	22%
Total	100%	**100%**	100%

Fair Value Measurements

Duke Energy classifies recurring and non-recurring fair value measurements based on the fair value hierarchy as discussed in Note 16.

Valuation methods of the primary fair value measurements disclosed below are as follows:

Investments in equity securities

Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the reporting period. Principal active markets for equity prices include published exchanges such as NASDAQ and NYSE. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. Prices have not been adjusted to reflect after-hours market activity. The majority of investments in equity securities are valued using Level 1 measurements. When the price of an institutional commingled fund is unpublished, it is not categorized in the fair value hierarchy, even though the funds are readily available at the fair value.

Investments in corporate debt securities and U.S. government securities

Most debt investments are valued based on a calculation using interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. Most debt valuations are Level 2 measurements. If the market for a particular fixed-income security is relatively inactive or illiquid, the measurement is Level 3. U.S. Treasury debt is typically Level 2.

Investments in short-term investment funds

Investments in short-term investment funds are valued at the net asset value of units held at year end and are readily redeemable at the measurement date. Investments in short-term investment funds with published prices are valued as Level 1. Investments in short-term investment funds with unpublished prices are valued as Level 2.

Investments in real estate limited partnerships

Investments in real estate limited partnerships are valued by the trustee at each valuation date (monthly). As part of the trustee's valuation process, properties are externally appraised generally on an annual basis, conducted by reputable, independent appraisal firms, and signed by appraisers that are members of the Appraisal Institute, with the professional designation MAI. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three valuation techniques that can be used to value investments in real estate assets: the market, income or cost approach. The appropriateness of each valuation technique depends on the type of asset or business being valued. In addition, the trustee may cause additional appraisals to be performed as warranted by specific asset or market conditions. Property valuations and the salient valuation-sensitive assumptions of each direct investment property are reviewed by the trustee quarterly and values are adjusted if there has been a significant change in circumstances related to the investment property since the last valuation. Value adjustments for interim capital expenditures are only recognized to the extent that the valuation process acknowledges a corresponding increase in fair value. An independent firm is hired to review and approve quarterly direct real estate valuations. Key inputs and assumptions used to determine fair value includes among others, rental revenue and expense amounts and related revenue and expense growth rates, terminal capitalization rates and discount rates. Development investments are valued using cost incurred to date as a primary input until substantive progress is achieved in terms of mitigating construction and leasing risk at which point a discounted cash flow approach is more heavily weighted. Key inputs and assumptions in addition to those noted above used to determine the fair value of development investments include construction costs and the status of construction completion and leasing. Investments in real estate limited partnerships are valued at net asset value of units held at year end and are not readily redeemable at the measurement date. Investments in real estate limited partnerships are not categorized within the fair value hierarchy.

Duke Energy Master Retirement Trust

The following tables provide the fair value measurement amounts for the Duke Energy Master Retirement Trust qualified pension and other post-retirement assets.

	December 31, 2017				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized(b)**
Equity securities	$ 2,823	$ 1,976	$ —	$ —	847
Corporate debt securities	4,694	—	4,694	—	—
Short-term investment funds	246	192	54	—	—
Partnership interests	137	—	—	—	137
Hedge funds	226	—	—	—	226
Real estate limited partnerships	135	—	—	—	135
U.S. government securities	762	—	762	—	—
Guaranteed investment contracts	28	—	—	28	—
Governments bonds – foreign	38	—	38	—	—
Cash	6	6	—	—	—
Government and commercial mortgage backed securities	2	—	2	—	—

Net pending transactions and other investments	**17**	**15**	**2**	**—**	**—**
Total assets(a)	**$ 9,114**	**$ 2,189**	**$ 5,552**	**$ 28**	**$ 1,345**

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 27 percent, 30 percent, 15 percent, 15 percent, 5 percent, 8 percent, and 4 percent, respectively, of the Duke Energy Master Retirement Trust at December 31, 2017. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments that are measured at fair value using the net asset value per share practical expedient have not been categorized in the fair value hierarchy.

	December 31, 2016				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized(b)**
Equity securities	$ 2,472	$ 1,677	$ 27	$ 9	759
Corporate debt securities	4,330	8	4,322	—	—
Short-term investment funds	476	211	265	—	—
Partnership interests	157	—	—	—	157
Hedge funds	232	—	—	—	232
Real estate limited partnerships	144	17	—	—	127
U.S. government securities	734	—	734	—	—
Guaranteed investment contracts	29	—	—	29	—
Governments bonds – foreign	32	—	32	—	—
Cash	17	15	2	—	—
Net pending transactions and other investments	32	1	6	—	25
Total assets(a)	$ 8,655	$ 1,929	$ 5,388	$ 38	$ 1,300

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana were allocated approximately 27 percent, 30 percent, 15 percent, 15 percent, 5 percent and 8 percent, respectively, of the Duke Energy Master Retirement Trust and Piedmont's Pension assets at December 31, 2016. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments that are measured at fair value using the net asset value per share practical expedient have not been categorized in the fair value hierarchy.

The following table provides a reconciliation of beginning and ending balances of Duke Energy Master Retirement Trust qualified pension and other post-retirement assets and Piedmont Pension Assets at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3).

(in millions)	**2017**	**2016**
Balance at January 1	**$ 38**	$ 31
Combination of Piedmont Pension Assets	**—**	9

Sales	**(2)**	(2)
Total gains (losses) and other, net	**1**	—
Transfer of Level 3 assets to other classifications	**(9)**	—
Balance at December 31	**$ 28**	$ 38

Other post-retirement assets

The following tables provide the fair value measurement amounts for VEBA trust assets.

	December 31, 2017	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	**$ 8**	**$ 8**
Real estate	**1**	**1**
Equity securities	**28**	**28**
Debt securities	**21**	**21**
Total assets	**$ 58**	**$ 58**

	December 31, 2016	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	$ 14	**$ 14**
Real estate	1	**1**
Equity securities	26	**26**
Debt securities	25	**25**
Total assets	$ 66	$ 66

EMPLOYEE SAVINGS PLANS

Retirement Savings Plan

Duke Energy or its affiliates sponsor, and the Subsidiary Registrants participate in, employee savings plans that cover substantially all U.S. employees. Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100 percent of employee before-tax and Roth 401(k) contributions of up to 6 percent of eligible pay per pay period (5 percent for Piedmont employees). Dividends on Duke Energy shares held by the savings plans are charged to retained earnings when declared and shares held in the plans are considered outstanding in the calculation of basic and diluted EPS.

As of January 1, 2014, for new and rehired non-union and certain unionized employees (excludes Piedmont employees until 2018 plan year, discussed below) who are not eligible to participate in Duke Energy's defined benefit plans, an additional employer contribution of 4 percent of eligible pay per pay period, which is subject to a three-year vesting schedule, is provided to the employee's savings plan account.

The following table includes pretax employer matching contributions made by Duke Energy and expensed by the Subsidiary Registrants.

(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont[(a)]**
Years ended December 31,								
2017	**$ 179**	**$ 61**	**$ 53**	**$ 37**	**$ 16**	**$ 3**	**$ 9**	**$ 7**

2016	169	57	50	35	15	3	8	—
2015	159	54	48	34	13	3	7	—

(a) Piedmont's pretax employer matching contributions were $1 million, $7 million and $7 million during the two months ended December 31, 2016 and for the years ended October 31, 2016 and 2015, respectively.

Money Purchase Pension Plan

Piedmont sponsors the MPP plan, which is a defined contribution pension plan that allows employees to direct investments and assume risk of investment returns. Under the MPP plan, Piedmont annually deposits a percentage of each participant's pay into an account of the MPP plan. This contribution equals 4 percent of the participant's eligible compensation plus an additional 4 percent of eligible compensation above the Social Security wage base up to the IRS compensation limit. The participant is vested in MPP plan after three years of service. No contributions were made to the MPP plan during the two months ended December 31, 2016. Piedmont contributed $2 million to the MPP plan during each of the years ended December 31, 2017, October 31, 2016 and 2015. Effective December 31, 2017, the MPP Plan was merged into the Retirement Savings Plan and the money purchase plan formula was discontinued. Beginning with the 2018 plan year, the former MPP Plan participants are eligible to receive the additional employer contribution under the Retirement Savings Plan, discussed above.

22. INCOME TAXES

Tax Act

On December 22, 2017, President Trump signed the Tax Act into law. Among other provisions, the Tax Act lowers the corporate federal income tax rate from 35 percent to 21 percent and eliminates bonus depreciation for regulated utilities, effective January 1, 2018. The Tax Act also could be amended or subject to technical correction, which could change the financial impacts that were recorded at December 31, 2017, or are expected to be recorded in future periods. The FERC and state utility commissions will determine the regulatory treatment of the impacts of the Tax Act for the Subsidiary Registrants. The Duke Energy Registrants' future results of operations, financial condition and cash flows could be adversely impacted by the Tax Act, subsequent amendments or corrections or the actions of the FERC, state utility commissions or credit rating agencies related to the Tax Act. Duke Energy is reviewing orders to address the rate treatment of the Tax Act by each state utility commission in which the Subsidiary Registrants operate. See Note 4 for additional information. Beginning in January 2018, the Subsidiary Registrants will defer the estimated ongoing impacts of the Tax Act that are expected to be returned to customers.

As a result of the Tax Act, Duke Energy revalued its existing deferred tax assets and deferred tax liabilities as of December 31, 2017, to account for the estimated future impact of lower corporate tax rates on these deferred tax amounts. For Duke Energy's regulated operations, where the reduction in the net accumulated deferred income tax (ADIT) liability is expected to be returned to customers in future rates, the net remeasurement has been deferred as a regulatory liability. The regulatory liability for income taxes includes the effect of the reduction of the net deferred tax liability including the tax gross-up of the excess accumulated deferred tax liabilities and the effect of the new tax rate on the previous regulatory asset for income taxes. Excess accumulated deferred income taxes are generally classified as either "protected" or "unprotected" under IRS rules. Protected excess ADIT, resulting from accumulated tax depreciation of public utility property, are required to utilize the average rate assumption method under the IRS normalization rules for determining the timing of the return to customers. The majority of the excess ADIT is related to protected amounts associated with public utility property. See Note 4 for additional information on the Tax Act's impact to the regulatory asset and liability accounts.

On December 22, 2017, the SEC staff issued Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118), which provides guidance on accounting for the Tax Act's impact. SAB 118 provides a measurement period, which in no case should extend beyond one year from the Tax Act enactment date, during which a company acting in good faith may complete the accounting for the impacts of the Tax Act under ASC Topic 740. In accordance with SAB 118, a company must reflect the income tax effects of the Tax Act in the reporting period in which the accounting under ASC Topic 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements in the first reporting period in which a reasonable estimate can be determined.

Duke Energy recorded a provisional net tax benefit of $112 million related to the Tax Act in the period ending December 31, 2017. This net benefit primarily consists of a net benefit of $534 million due to the remeasurement of deferred tax accounts to reflect the corporate rate reduction impact to net deferred tax balances, a net expense for the establishment of a valuation allowance related to foreign tax credits of $406 million and a transition tax on previously untaxed earnings and profits on foreign subsidiaries of $10 million. The majority of Duke Energy’s operations are regulated and it is expected that the Subsidiary Registrants will ultimately pass on the savings associated with the amount representing the remeasurement of deferred tax balances related to regulated operations to customers. Duke Energy recorded a regulatory liability of $8,313 million, representing the revaluation of those deferred tax balances. The Subsidiary Registrants continue to respond to requests from regulators in various jurisdictions to determine the timing and magnitude of savings they will pass on to customers.

The net provisional charge from deferred tax remeasurement and assessment of valuation allowance is based on currently available information and interpretations which are continuing to evolve. Duke Energy continues to analyze additional information and guidance related to certain aspects of the Tax Act, such as limitations on the deductibility of interest and executive compensation, conformity or decoupling by state legislatures in response to the Tax Act, and the final determination of the net deferred tax liabilities subject to the remeasurement. The prospects of supplemental legislation or regulatory processes to address questions that arise because of the Tax Act, or evolving technical interpretations of the tax law, may also cause the final impact from the Tax Act to differ from the estimated amounts. Duke Energy continues to appropriately refine such amounts within the measurement period allowed by SAB 118, which will be completed no later than the fourth quarter of 2018.

Income Tax Expense

Components of Income Tax Expense

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current income taxes								
Federal	$ (247)	$ 221	$ (436)	$ (95)	$ (188)	$ (37)	$ 128	$ (90)
State	4	20	(5)	2	(11)	2	21	(3)
Foreign	3	—	—	—	—	—	—	—
Total current income taxes	(240)	241	(441)	(93)	(199)	(35)	149	(93)
Deferred income taxes								
Federal	1,344	381	664	378	194	99	138	147
State	102	35	44	10	51	(4)	14	8
Total deferred income taxes(a) (b)	1,446	416	708	388	245	95	152	155
Investment tax credit amortization	(10)	(5)	(3)	(3)	—	(1)	—	—
Income tax expense from continuing operations	1,196	652	264	292	46	59	301	62
Tax benefit from discontinued operations	(6)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,190	$ 652	$ 264	$ 292	$ 46	$ 59	$ 301	$ 62

(a) Includes utilization of NOL (Net operating loss) carryforwards and tax credit carryforwards of $428 million at Duke Energy, $74 million at Progress Energy, $36 million at Duke Energy Florida, $17 million at Duke Energy Ohio, $42 million at Duke Energy Indiana and $79 million at Piedmont. In addition the total deferred income taxes Includes benefits of NOL carryforwards and tax credit carryforwards of $10 million at Duke Energy Carolinas and $1 million at Duke Energy Progress.

(b) As a result of the Tax Act, Duke Energy's deferred tax assets and liabilities were revalued as of December 31, 2017. See the Statutory Rate Reconciliation section below for additional information on the Tax Act's impact on income tax expense.

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Current income taxes							
Federal	$ —	$ 139	$ 15	$ (59)	$ 76	$ (7)	$ 7
State	(15)	25	(19)	(25)	22	(13)	6
Foreign	2	—	—	—	—	—	—
Total current income taxes	(13)	164	(4)	(84)	98	(20)	13
Deferred income taxes							
Federal	1,064	430	486	350	199	88	202
State	117	45	50	40	25	11	11
Total deferred income taxes[(a)]	1,181	475	536	390	224	99	213
Investment tax credit amortization	(12)	(5)	(5)	(5)	—	(1)	(1)
Income tax expense from continuing operations	1,156	634	527	301	322	78	225
Tax (benefit) expense from discontinued operations	(30)	—	1	—	—	(36)	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,126	$ 634	$ 528	$ 301	$ 322	$ 42	$ 225

(a) Includes benefits of NOL carryforwards and utilization of NOL and tax credit carryforwards of $648 million at Duke Energy, $4 million at Duke Energy Carolinas, $190 million at Progress Energy, $60 million at Duke Energy Progress, $49 million at Duke Energy Florida, $26 million at Duke Energy Ohio and $58 million at Duke Energy Indiana.

	Year Ended December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Current income taxes							
Federal	$ —	$ 216	$ (193)	$ (56)	$ 1	$ (18)	$ (86)
State	(12)	14	1	(4)	(7)	(1)	(12)
Foreign	4	—	—	—	—	—	—
Total current income taxes	(8)	230	(192)	(60)	(6)	(19)	(98)
Deferred income taxes							
Federal	1,097	345	694	334	290	96	245
State	181	57	27	27	58	5	17
Total deferred income taxes[(a)]	1,278	402	721	361	348	101	262
Investment tax credit amortization	(14)	(5)	(7)	(7)	—	(1)	(1)
Income tax expense from continuing operations	1,256	627	522	294	342	81	163

Tax expense (benefit) from discontinued operations	89	—	(1)	—	—	22	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,345	$ 627	$ 521	$ 294	$ 342	$ 103	$ 163

(a) Includes utilization of NOL carryforwards and tax credit carryforwards of $264 million at Duke Energy, $15 million at Duke Energy Carolinas, $119 million at Progress Energy, $21 million at Duke Energy Progress, $84 million at Duke Energy Florida, $3 million at Duke Energy Ohio and $45 million at Duke Energy Indiana.

	Piedmont		
	Two Months Ended	Years Ended October 31,	
(in millions)	December 31, 2016	2016	2015
Current income taxes			
Federal	$ 4	$ 27	$ (1)
State	(2)	12	1
Total current income taxes	2	39	—
Deferred income taxes			
Federal	24	79	78
State	6	6	12
Total deferred income taxes(a)(b)	30	85	90
Total income tax expense from continuing operations included in Consolidated Statements of Operations	$ 32	$ 124	$ 90

(a) Includes benefits of NOL and tax carryforwards of $17 million and $91 million for the two months ended December 31, 2016, and the year ended October 31, 2016, respectively.
(b) Includes benefits and utilization of NOL carryforwards of $46 million for the year ended October 31, 2015.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	2017	2016	2015
Domestic(a)	**$ 4,207**	$ 3,689	$ 3,831
Foreign	**59**	45	79
Income from continuing operations before income taxes	**$ 4,266**	$ 3,734	$ 3,910

(a) Includes a $16 million expense in 2017 related to the Tax Act impact on equity earnings included within Equity in earnings (losses) of unconsolidated affiliates on the Consolidated Statement of Operations.

Taxes on Foreign Earnings

In February 2016, Duke Energy announced it had initiated a process to divest the International Disposal Group and, accordingly, no longer intended to indefinitely reinvest post-2014 undistributed foreign earnings. This change in the company's intent, combined with the extension of bonus depreciation by Congress in late 2015, allowed Duke Energy to more efficiently utilize foreign tax credits and reduce U.S. deferred tax liabilities associated with the historical unremitted foreign earnings by approximately $95 million during the year ended December 31, 2016.

Due to the classification of the International Disposal Group as discontinued operations beginning in the fourth quarter of 2016, income tax amounts related to the International Disposal Group's foreign earnings are presented within (Loss) Income From Discontinued Operations, net of tax on the Consolidated Statements of Operations. In December 2016, Duke Energy closed on the sale of the International Disposal Group in two separate transactions to execute the divestiture. See Note 2 for additional information on the sale.

Statutory Rate Reconciliation

The following tables present a reconciliation of income tax expense at the U.S. federal statutory tax rate to the actual tax expense from continuing operations.

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Income tax expense, computed at the statutory rate of 35 percent	**$ 1,493**	**$ 653**	**$ 536**	**$ 353**	**$ 265**	**$ 88**	**$ 229**	**$ 70**
State income tax, net of federal income tax effect	**69**	**36**	**25**	**8**	**26**	**(1)**	**23**	**3**
AFUDC equity income	**(81)**	**(37)**	**(32)**	**(17)**	**(16)**	**(4)**	**(8)**	**—**
Renewable energy production tax credits	**(132)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Tax Act[(a)]	**(112)**	**15**	**(246)**	**(40)**	**(226)**	**(23)**	**55**	**(12)**
Tax true-up	**(52)**	**(24)**	**(19)**	**(13)**	**(7)**	**(5)**	**(6)**	**—**
Other items, net	**11**	**9**	**—**	**1**	**4**	**4**	**8**	**1**
Income tax expense from continuing operations	**$ 1,196**	**$ 652**	**$ 264**	**$ 292**	**$ 46**	**$ 59**	**$ 301**	**$ 62**
Effective tax rate	**28.0%**	**34.9%**	**17.2%**	**29.0%**	**6.1%**	**23.4%**	**46.0%**	**30.8%**

(a) Amounts primarily include but are not limited to items that are excluded for ratemaking purposes related to abandoned or impaired assets, certain wholesale fixed rate contracts, remeasurement of nonregulated net deferred tax liabilities, Federal net operating losses, and valuation allowance on foreign tax credits.

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Income tax expense, computed at the statutory rate of 35 percent	$ 1,307	$ 630	$ 548	$ 315	$ 306	$ 95	$ 212
State income tax, net of federal income tax effect	64	46	20	10	30	(2)	11
AFUDC equity income	(70)	(36)	(26)	(17)	(9)	(2)	(6)
Renewable energy production tax credits	(97)	—	—	—	—	—	—
Audit adjustment	5	3	—	—	—	—	—
Tax true-up	(14)	(14)	(11)	(3)	(9)	(16)	2
Other items, net	(39)	5	(4)	(4)	4	3	6
Income tax expense from continuing operations	$ 1,156	$ 634	$ 527	$ 301	$ 322	$ 78	$ 225
Effective tax rate	31.0%	35.2%	33.7%	33.4%	36.9%	28.9%	37.1%

	Year Ended December 31, 2015						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Income tax expense, computed at the statutory rate of 35 percent	$ 1,369	$ 598	$ 555	$ 302	$ 330	$ 81	$ 168
State income tax, net of federal income tax effect	109	46	18	15	33	2	2
AFUDC equity income	(58)	(34)	(19)	(17)	(3)	(1)	(4)
Renewable energy production tax credits	(72)	—	(1)	—	—	—	—
Audit adjustment	(22)	—	(23)	1	(24)	—	—
Tax true-up	2	2	(3)	(4)	2	(5)	(9)
Other items, net	(72)	15	(5)	(3)	4	4	6
Income tax expense from continuing operations	$ 1,256	$ 627	$ 522	$ 294	$ 342	$ 81	$ 163
Effective tax rate	32.1%	36.7%	32.9%	34.2%	36.3%	35.2%	34.0%

	Piedmont		
	Two Months Ended	**Years Ended October 31,**	
(in millions)	**December 31, 2016**	**2016**	**2015**
Income tax expense, computed at the statutory rate of 35 percent	$ 30	$ 111	$ 79
State income tax, net of federal income tax effect	1	11	9
Other items, net	1	2	2
Income tax expense from continuing operations	$ 32	$ 124	$ 90
Effective tax rate	37.2%	39.1%	39.7%

Valuation allowances have been established for certain state NOL carryforwards and state income tax credits that reduce deferred tax assets to an amount that will be realized on a more-likely-than-not basis. The net change in the total valuation allowance is included in the State income tax, net of federal income tax effect in the above tables.

DEFERRED TAXES

Net Deferred Income Tax Liability Components

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Deferred credits and other liabilities	$ 143	$ 33	$ 78	$ 23	$ 49	$ 11	$ 6	$ (5)
Capital lease obligations	49	14	—	—	—	—	2	—
Pension, post-retirement and other employee benefits	295	(17)	111	44	60	14	18	(4)
Progress Energy merger purchase accounting adjustments[(a)]	536	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,527	234	402	156	143	25	216	70
Regulatory liabilities and deferred credits	—	222	—	—	—	65	—	61
Investments and other assets	—	—	—	—	—	—	1	18
Other	73	10	1	4	—	—	—	—
Valuation allowance	(519)	—	(14)	—	—	—	—	—
Total deferred income tax assets	5,104	496	578	227	252	115	243	140
Investments and other assets	(1,419)	(849)	(470)	(289)	(187)	—	(14)	—
Accelerated depreciation rates	(9,216)	(3,060)	(2,803)	(1,583)	(1,257)	(896)	(966)	(697)
Regulatory assets and deferred debits, net	(1,090)	—	(807)	(238)	(569)	—	(188)	—
Other	—	—	—	—	—	—	—	(7)
Total deferred income tax liabilities	(11,725)	(3,909)	(4,080)	(2,110)	(2,013)	(896)	(1,168)	(704)
Net deferred income tax liabilities	$ (6,621)	$ (3,413)	$ (3,502)	$ (1,883)	$ (1,761)	$ (781)	$ (925)	$ (564)

(a) Primarily related to capital lease obligations and debt fair value adjustments.

As noted above, as a result of the Tax Act, Duke Energy revalued its existing deferred tax assets and liabilities as of December 31, 2017, to account for the estimated future impact of lower corporate tax rates on these deferred amounts. The following table shows the decrease reflected in the net deferred income tax liabilities balance above:

(in millions)	**December 31, 2017**
Duke Energy	$ 8,982
Duke Energy Carolinas	3,454
Progress Energy	3,282
Duke Energy Progress	1,882
Duke Energy Florida	1,420
Duke Energy Ohio	771
Duke Energy Indiana	1,053
Piedmont	521

The following table presents the expiration of tax credits and NOL carryforwards.

	December 31, 2017				
(in millions)	Amount	Expiration Year			
Investment tax credits	$	1,406	2024	—	2037
Alternative minimum tax credits		1,147	Refundable by 2021		
Federal NOL carryforwards		393	2022	—	2036
State NOL carryforwards and credits[a]		296	2018	—	2037
Foreign NOL carryforwards[b]		13	2027	—	2036
Foreign Tax Credits[c]		1,272	2024	—	2027
Total tax credits and NOL carryforwards		4,527			

(a) A valuation allowance of $90 million has been recorded on the state NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(b) A valuation allowance of $13 million has been recorded on the foreign NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(c) A valuation allowance of $416 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.

	December 31, 2016							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Deferred credits and other liabilities	$ 382	$ 66	$ 126	$ 40	$ 93	$ 21	$ 4	$ 71
Capital lease obligations	60	8	—	—	—	—	1	—
Pension, post-retirement and other employee benefits	561	16	199	91	96	22	37	10
Progress Energy merger purchase accounting adjustments[a]	918	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,682	192	1,165	222	232	49	278	192
Investments and other assets	—	—	—	—	—	3	—	—
Other	205	16	35	8	—	5	9	45
Valuation allowance	(96)	—	(12)	—	—	—	—	(1)
Total deferred income tax assets	6,712	298	1,513	361	421	100	329	317
Investments and other assets	(1,892)	(1,149)	(597)	(313)	(297)	—	(21)	(21)
Accelerated depreciation rates	(14,872)	(4,664)	(4,490)	(2,479)	(2,038)	(1,404)	(1,938)	(1,080)
Regulatory assets and deferred debits, net	(4,103)	(1,029)	(1,672)	(892)	(780)	(139)	(270)	(147)
Total deferred income tax liabilities	(20,867)	(6,842)	(6,759)	(3,684)	(3,115)	(1,543)	(2,229)	(1,248)
Net deferred income tax liabilities	$ (14,155)	$ (6,544)	$ (5,246)	$ (3,323)	$ (2,694)	$ (1,443)	$ (1,900)	$ (931)

(a) Primarily related to capital lease obligations and debt fair value adjustments.

On August 6, 2015, pursuant to N.C. Gen. Stat. 105-130.3C, the North Carolina Department of Revenue announced the North Carolina corporate income tax rate would be reduced from a statutory rate of 5.0 percent to 4.0 percent beginning January 1, 2016. Duke Energy and Piedmont recorded net reductions of approximately $95 million and $18 million to their North Carolina deferred tax liabilities in the third quarter of 2015. The significant majority of these deferred tax liability reductions were offset by recording a regulatory liability pending NCUC determination of the disposition of amounts related to Duke Energy Carolinas, Duke Energy Progress and Piedmont. The impact did not have a significant impact on the financial position, results of operation, or cash flows of Duke Energy, Duke Energy Carolinas, Progress Energy or Duke Energy Progress.

On August 4, 2016, pursuant to N.C. Gen. Stat. 105-130.3C, the North Carolina Department of Revenue announced the North Carolina corporate income tax rate would be reduced from a statutory rate of 4.0 percent to 3.0 percent beginning January 1, 2017. Duke Energy and Piedmont recorded net reductions of approximately $80 million and $16 million to their North Carolina deferred tax liabilities in the third quarter of 2016. The significant majority of this deferred tax liability reduction was offset by recording a regulatory liability pending NCUC determination of the disposition of amounts related to Duke Energy Carolinas, Duke Energy Progress and Piedmont. The impact did not have a significant impact on the financial position, results of operation, or cash flows of Duke Energy, Duke Energy Carolinas, Progress Energy or Duke Energy Progress.

On June 28, 2017, the North Carolina General Assembly amended N.C. Gen. Stat. 105-130.3, reducing the North Carolina corporate income tax rate from a statutory rate of 3.0 percent to 2.5 percent beginning January 1, 2019. Duke Energy recorded a net reduction of approximately $55 million to their North Carolina deferred tax liabilities in the second quarter of 2017. The significant majority of this deferred tax liability reduction was offset by recording a regulatory liability pending NCUC determination of the disposition of amounts related to Duke Energy Carolinas, Duke Energy Progress and Piedmont. The impact did not have a significant impact on the financial position, results of operation or cash flows of Duke Energy, Duke Energy Carolinas, Progress Energy or Duke Energy Progress.

UNRECOGNIZED TAX BENEFITS

The following tables present changes to unrecognized tax benefits.

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Unrecognized tax benefits – January 1	$ 17	$ 1	$ 2	$ 2	$ 4	$ 4	$ —	$ —
Unrecognized tax benefits increases (decreases)								
Gross increases – tax positions in prior periods	12	4	3	3	1	1	1	3
Gross decreases – tax positions in prior periods	(4)	—	—	—	—	(4)	—	—
Total changes	8	4	3	3	1	(3)	1	3
Unrecognized tax benefits – December 31	$ 25	$ 5	$ 5	$ 5	$ 5	$ 1	$ 1	$ 3

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Unrecognized tax benefits – January 1	$ 88	$ 72	$ 1	$ 3	$ —	$ —	$ 1
Unrecognized tax benefits increases (decreases)							
Gross increases – tax positions in prior periods	—	—	—	—	4	4	—
Gross decreases – tax positions in prior periods	(4)	(4)	(1)	(1)	—	—	—
Decreases due to settlements	(68)	(67)	—	—	—	—	(1)
Reduction due to lapse of statute of limitations	1	—	2	—	—	—	—
Total changes	(71)	(71)	1	(1)	4	4	(1)
Unrecognized tax benefits – December 31	$ 17	$ 1	$ 2	$ 2	$ 4	$ 4	$ —

	Year Ended December 31, 2015					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Indiana**
Unrecognized tax benefits – January 1	$ 213	$ 160	$ 32	$ 23	$ 8	$ 1

Unrecognized tax benefits increases (decreases)						
Gross increases – tax positions in prior periods	—	—	1	1	—	—
Gross decreases – tax positions in prior periods	(48)	(45)	—	—	—	—
Decreases due to settlements	(45)	(43)	—	—	—	—
Reduction due to lapse of statute of limitations	(32)	—	(32)	(21)	(8)	—
Total changes	(125)	(88)	(31)	(20)	(8)	—
Unrecognized tax benefits – December 31	$ 88	$ 72	$ 1	$ 3	$ —	$ 1

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2017. During the first quarter of 2018, Duke Energy recognized an approximate $8 million reduction and Duke Energy Carolinas recognized an approximate $1 million reduction in unrecognized tax benefits. No additional material reductions are expected in the next 12 months.

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	**$ 15**	**$ 4**	**$ 7**	**$ 5**	**$ 1**	**$ 1**	**$ 1**	**$ 3**
Amount that if recognized, would be recorded as a component of discontinued operations	**7**	**—**	**—**	**—**	**—**	**2**	**—**	**—**

(a) Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana and Piedmont are unable to estimate the specific amounts that would affect the effective tax rate versus the regulatory liability.

OTHER TAX MATTERS

The following tables include interest recognized in the Consolidated Statements of Operations and the Consolidated Balance Sheets.

	Year Ended December 31, 2017				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Net interest income recognized related to income taxes	**$ —**	**$ —**	**$ 1**	**$ —**	**$ 1**
Net interest expense recognized related to income taxes	**—**	**2**	**—**	**—**	**—**
Interest payable related to income taxes	**5**	**25**	**1**	**1**	**—**

	Year Ended December 31, 2016				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**
Net interest income recognized related to income taxes	$ —	$ —	$ 1	$ —	$ 2
Net interest expense recognized related to income taxes	—	7	—	—	—
Interest payable related to income taxes	4	23	1	1	—

Year Ended December 31, 2015

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
Net interest income recognized related to income taxes	$ 12	$ —	$ 2	$ 2	$ 1	$ 1
Net interest expense recognized related to income taxes	—	1	—	—	—	—
Interest receivable related to income taxes	3	—	—	—	—	3
Interest payable related to income taxes	—	14	—	1	—	—

Piedmont recognized $1 million in net interest income recognized related to income taxes in the Consolidated Statements of Operations for the year ended October 31, 2016.

Duke Energy and its subsidiaries are no longer subject to U.S. federal examination for years before 2015. With few exceptions, Duke Energy and its subsidiaries are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2015.

23. OTHER INCOME AND EXPENSES, NET

The components of Other income and expenses, net on the Consolidated Statements of Operations are as follows. Amounts for Piedmont were not material.

	Year Ended December 31, 2017						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Interest income	**$ 13**	**$ 2**	**$ 6**	**$ 2**	**$ 5**	**$ 6**	**$ 8**
AFUDC equity	**237**	**106**	**92**	**47**	**45**	**11**	**28**
Post in-service equity returns	**40**	**28**	**12**	**12**	**—**	**—**	**—**
Nonoperating income, other	**62**	**3**	**18**	**4**	**11**	**—**	**1**
Other income and expense, net	**$ 352**	**$ 139**	**$ 128**	**$ 65**	**$ 61**	**$ 17**	**$ 37**

	Year Ended December 31, 2016						
	Duke	**Duke Energy**	**Progress**	**Duke Energy**	**Duke Energy**	**Duke Energy**	**Duke Energy**

(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana
Interest income	$ 21	$ 4	$ 4	$ 3	$ 2	$ 5	$ 6
AFUDC equity	200	102	76	50	26	6	16
Post in-service equity returns	67	55	12	12	—	—	—
Nonoperating income (expense), other	36	1	22	6	16	(2)	—
Other income and expense, net	$ 324	$ 162	$ 114	$ 71	$ 44	$ 9	$ 22

	Year Ended December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Interest income	$ 20	$ 2	$ 4	$ 2	$ 2	$ 4	$ 6
AFUDC equity	164	96	54	47	7	3	11
Post in-service equity returns	73	60	13	13	—	—	—
Nonoperating income (expense), other	33	2	26	9	15	(1)	(6)
Other income and expense, net	$ 290	$ 160	$ 97	$ 71	$ 24	$ 6	$ 11

24. SUBSEQUENT EVENTS

For information on subsequent events related to regulatory matters, commitments and contingencies, debt and credit facilities, investments in unconsolidated affiliates, variable interest entities and common stock see Notes 4, 5, 6, 12, 17 and 18, respectively.

25. QUARTERLY FINANCIAL DATA (UNAUDITED)

DUKE ENERGY

Quarterly EPS amounts may not sum to the full-year total due to changes in the weighted average number of common shares outstanding and rounding.

(in millions, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 5,729**	**$ 5,555**	**$ 6,482**	**$ 5,799**	**$ 23,565**
Operating income	**1,437**	**1,387**	**1,695**	**1,262**	**5,781**
Income from continuing operations	**717**	**691**	**957**	**705**	**3,070**
Loss from discontinued operations, net of tax	**—**	**(2)**	**(2)**	**(2)**	**(6)**
Net income	**717**	**689**	**955**	**703**	**3,064**
Net income attributable to Duke Energy Corporation	**716**	**686**	**954**	**703**	**3,059**
Earnings per share:					
Income from continuing operations attributable to Duke Energy Corporation common stockholders					
Basic	**$ 1.02**	**$ 0.98**	**$ 1.36**	**$ 1.00**	**$ 4.37**
Diluted	**$ 1.02**	**$ 0.98**	**$ 1.36**	**$ 1.00**	**$ 4.37**
Loss from discontinued operations attributable to Duke Energy Corporation common stockholders					
Basic	**$ —**	**$ —**	**$ —**	**$ —**	**$ (0.01)**
Diluted	**$ —**	**$ —**	**$ —**	**$ —**	**$ (0.01)**
Net income attributable to Duke Energy Corporation common					

stockholders										
Basic	**$**	**1.02**	**$**	**0.98**	**$**	**1.36**	**$**	**1.00**	**$**	**4.36**
Diluted	**$**	**1.02**	**$**	**0.98**	**$**	**1.36**	**$**	**1.00**	**$**	**4.36**
2016										
Operating revenues	$	5,377	$	5,213	$	6,576	$	5,577	$	22,743
Operating income		1,240		1,259		1,954		888		5,341
Income from continuing operations		577		624		1,001		376		2,578
Income (Loss) from discontinued operations, net of tax		122		(112)		180		(598)		(408)
Net income (loss)		699		512		1,181		(222)		2,170
Net income (loss) attributable to Duke Energy Corporation		694		509		1,176		(227)		2,152
Earnings per share:										
Income from continuing operations attributable to Duke Energy Corporation common stockholders										
Basic	$	0.83	$	0.90	$	1.44	$	0.53	$	3.71
Diluted	$	0.83	$	0.90	$	1.44	$	0.53	$	3.71
Income (Loss) from discontinued operations attributable to Duke Energy Corporation common stockholders										
Basic	$	0.18	$	(0.16)	$	0.26	$	(0.86)	$	(0.60)
Diluted	$	0.18	$	(0.16)	$	0.26	$	(0.86)	$	(0.60)
Net income (loss) attributable to Duke Energy Corporation common stockholders										
Basic	$	1.01	$	0.74	$	1.70	$	(0.33)	$	3.11
Diluted	$	1.01	$	0.74	$	1.70	$	(0.33)	$	3.11

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)		**First Quarter**		**Second Quarter**		**Third Quarter**		**Fourth Quarter**		**Total**
2017										
Costs to Achieve Piedmont Merger (see Note 2)	**$**	**(16)**	**$**	**(30)**	**$**	**(23)**	**$**	**(34)**	**$**	**(103)**
Regulatory Settlements (see Note 4)		**—**		**—**		**(135)**		**(23)**		**(158)**
Commercial Renewables Impairments (see Notes 10 and 11)		**—**		**—**		**(84)**		**(18)**		**(102)**
Impacts of the Tax Act (see Note 22)		**—**		**—**		**—**		**102**		**102**
Total	**$**	**(16)**	**$**	**(30)**	**$**	**(242)**	**$**	**27**	**$**	**(261)**
2016										
Costs to Achieve Mergers (see Note 2)	$	(120)	$	(111)	$	(84)	$	(208)	$	(523)
Commercial Renewables Impairment (see Note 12)		—		—		(71)		—		(71)
Loss on Sale of International Disposal Group (see Note 2)		—		—		—		(514)		(514)
Impairment of Assets in Central America (see Note 2)		—		(194)		—		—		(194)
Cost Savings Initiatives (see Note 19)		(20)		(24)		(19)		(29)		(92)
Total	$	(140)	$	(329)	$	(174)	$	(751)	$	(1,394)

DUKE ENERGY CAROLINAS

(in millions)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**

2017										
Operating revenues	**$**	**1,716**	**$**	**1,729**	**$**	**2,136**	**$**	**1,721**	**$**	**7,302**
Operating income		**484**		**485**		**777**		**403**		**2,149**
Net income		**270**		**273**		**466**		**205**		**1,214**
2016										
Operating revenues	$	1,740	$	1,675	$	2,226	$	1,681	$	7,322
Operating income		481		464		815		302		2,062
Net income		271		261		494		140		1,166

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)		**First Quarter**		**Second Quarter**		**Third Quarter**		**Fourth Quarter**		**Total**
2017										
Costs to Achieve Piedmont Merger (see Note 2)	**$**	**(4)**	**$**	**(6)**	**$**	**(5)**	**$**	**(5)**	**$**	**(20)**
Impacts of the Tax Act (see Note 22)		**—**		**—**		**—**		**(15)**		**(15)**
Total	**$**	**(4)**	**$**	**(6)**	**$**	**(5)**	**$**	**(20)**	**$**	**(35)**
2016										
Costs to Achieve Mergers	$	(11)	$	(12)	$	(13)	$	(68)	$	(104)
Cost Savings Initiatives (see Note 19)		(10)		(10)		(8)		(11)		(39)
Total	$	(21)	$	(22)	$	(21)	$	(79)	$	(143)

PROGRESS ENERGY

(in millions)		**First Quarter**		**Second Quarter**		**Third Quarter**		**Fourth Quarter**		**Total**
2017										
Operating revenues	**$**	**2,179**	**$**	**2,392**	**$**	**2,864**	**$**	**2,348**	**$**	**9,783**
Operating income		**487**		**591**		**657**		**493**		**2,228**
Net income		**201**		**277**		**343**		**447**		**1,268**
Net income attributable to Parent		**199**		**274**		**341**		**444**		**1,258**
2016										
Operating revenues	$	2,332	$	2,348	$	2,965	$	2,208	$	9,853
Operating income		475		560		814		292		2,141
Income from continuing operations		212		274		449		104		1,039
Net income		212		274		449		106		1,041
Net income attributable to Parent		209		272		446		104		1,031

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (4)**	**$ (7)**	**$ (6)**	**$ (6)**	**$ (23)**
Regulatory Settlements (see Note 4)	**—**	**—**	**(135)**	**(23)**	**(158)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**246**	**246**
Total	**$ (4)**	**$ (7)**	**$ (141)**	**$ 217**	**$ 65**
2016					
Costs to Achieve Mergers	$ (7)	$ (8)	$ (10)	$ (44)	$ (69)
Cost Savings Initiatives (see Note 19)	(8)	(8)	(10)	(14)	(40)
Total	$ (15)	$ (16)	$ (20)	$ (58)	$ (109)

DUKE ENERGY PROGRESS

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 1,219**	**$ 1,199**	**$ 1,460**	**$ 1,251**	**$ 5,129**
Operating income	**286**	**282**	**411**	**256**	**1,235**
Net income	**147**	**154**	**246**	**168**	**715**
2016					
Operating revenues	$ 1,307	$ 1,213	$ 1,583	$ 1,174	$ 5,277
Operating income	258	255	438	135	1,086
Net income	137	131	271	60	599

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (2)**	**$ (4)**	**$ (4)**	**$ (4)**	**$ (14)**
Regulatory Settlements (see Note 4)	**—**	**—**	**—**	**(23)**	**(23)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**40**	**40**
Total	**$ (2)**	**$ (4)**	**$ (4)**	**$ 13**	**$ 3**
2016					
Costs to Achieve Mergers	$ (5)	$ (5)	$ (6)	$ (40)	$ (56)
Cost Savings Initiatives (see Note 19)	(5)	(5)	(7)	(6)	(23)
Total	$ (10)	$ (10)	$ (13)	$ (46)	$ (79)

DUKE ENERGY FLORIDA

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 959**	**$ 1,191**	**$ 1,401**	**$ 1,095**	**$ 4,646**
Operating income	**196**	**306**	**240**	**234**	**976**
Net income	**90**	**158**	**120**	**344**	**712**
2016					
Operating revenues	$ 1,024	$ 1,133	$ 1,381	$ 1,030	$ 4,568
Operating income	213	300	373	155	1,041
Net income	110	171	206	64	551

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

	First	Second	Third	Fourth

(in millions)	Quarter	Quarter	Quarter	Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (2)**	**$ (3)**	**$ (2)**	**$ (2)**	**$ (9)**
Regulatory Settlements (see Note 4)	**—**	**—**	**(135)**	**—**	**(135)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**226**	**226**
Total	**$ (2)**	**$ (3)**	**$ (137)**	**$ 224**	**$ 82**
2016					
Costs to Achieve Mergers	$ (2)	$ (3)	$ (4)	$ (4)	$ (13)
Cost Savings Initiatives (see Note 19)	(2)	(3)	(3)	(9)	(17)
Total	$ (4)	$ (6)	$ (7)	$ (13)	$ (30)

DUKE ENERGY OHIO

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 518**	**$ 437**	**$ 471**	**$ 497**	**$ 1,923**
Operating income	**83**	**65**	**102**	**76**	**326**
Loss from discontinued operations, net of tax	**—**	**—**	**(1)**	**—**	**(1)**
Net income	**42**	**30**	**55**	**65**	**192**
2016					
Operating revenues	$ 516	$ 428	$ 489	$ 511	$ 1,944
Operating income	96	55	106	90	347
Income from discontinued operations, net of tax	2	—	34	—	36
Net income	59	23	89	57	228

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (1)**	**$ (1)**	**$ (2)**	**$ (2)**	**$ (6)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**23**	**23**
Total	**$ (1)**	**$ (1)**	**$ (2)**	**$ 21**	**$ 17**
2016					
Costs to Achieve Mergers	$ (1)	$ (1)	$ (2)	$ (2)	$ (6)
Cost Savings Initiatives (see Note 19)	(1)	(1)	—	(1)	(3)
Total	$ (2)	$ (2)	$ (2)	$ (3)	$ (9)

DUKE ENERGY INDIANA

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Operating revenues	**$ 758**	**$ 742**	**$ 802**	**$ 745**	**$ 3,047**

Operating income	**186**	**210**	**230**	**170**	**796**
Net income	**91**	**106**	**121**	**36**	**354**
2016					
Operating revenues	$ 714	$ 702	$ 809	$ 733	$ 2,958
Operating income	176	174	239	176	765
Net income	95	85	129	72	381

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (1)**	**$ (2)**	**$ (2)**	**$ (1)**	**$ (6)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**(55)**	**(55)**
Total	**$ (1)**	**$ (2)**	**$ (2)**	**$ (56)**	**$ (61)**
2016					
Costs to Achieve Mergers	$ (1)	$ (2)	$ (3)	$ (3)	$ (9)
Cost Savings Initiatives (see Note 19)	(1)	(4)	(1)	(1)	(7)
Total	$ (2)	$ (6)	$ (4)	$ (4)	$ (16)

PIEDMONT

The following tables include data for Piedmont's fiscal years ending December 31, 2017, and October 31, 2016.

(in millions)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2017					
Operating revenues	**$ 500**	**$ 201**	**$ 183**	**$ 444**	**$ 1,328**
Operating income (loss)	**170**	**5**	**(4)**	**115**	**286**
Net income (loss)	**95**	**(8)**	**(11)**	**63**	**139**
2016					
Operating revenues	$ 464	$ 353	$ 160	$ 172	$ 1,149
Operating income (loss)	171	104	—	(50)	225
Net income (loss)	98	63	(7)	39	193

For the two months ended December 31, 2016, Piedmont's operating revenues, operating income, and net income were $322 million, $96 million and $54 million, respectively.

The following table includes unusual or infrequently occurring items in each quarter during the two most recently completed fiscal years. All amounts discussed below are pretax.

(in millions)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2017					
Costs to Achieve Piedmont Merger (see Note 2)	**$ (6)**	**$ (13)**	**$ (8)**	**$ (19)**	**$ (46)**
Impacts of the Tax Act (see Note 22)	**—**	**—**	**—**	**2**	**2**
Total	**$ (6)**	**$ (13)**	**$ (8)**	**$ (17)**	**$ (44)**
2016					

Costs to Achieve Mergers	$ (6)	$ (2)	$ (1)	$ (53)	$ (62)

For the two months ended December 31, 2016, Piedmont's costs to achieve merger were $7 million.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		(232,257)	(232,257)		
2		25,611	25,611		
3					
4		25,611	25,611	599,400,762	599,426,373
5		(206,646)	(206,646)		
6		(206,646)	(206,646)		
7		25,837	25,837		
8					
9		25,837	25,837	715,397,849	715,423,686
10		(180,809)	(180,809)		

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	04/12/2018	End of 2017/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	23,136,321,819	23,136,321,819
4	Property Under Capital Leases	139,410,389	139,410,389
5	Plant Purchased or Sold		
6	Completed Construction not Classified	3,968,168,075	3,968,168,075
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	27,243,900,283	27,243,900,283
9	Leased to Others		
10	Held for Future Use	46,711,200	46,711,200
11	Construction Work in Progress	1,422,282,356	1,422,282,356
12	Acquisition Adjustments	349,801,943	349,801,943
13	Total Utility Plant (8 thru 12)	29,062,695,782	29,062,695,782
14	Accum Prov for Depr, Amort, & Depl	11,818,924,780	11,818,924,780
15	Net Utility Plant (13 less 14)	17,243,771,002	17,243,771,002
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	11,506,301,729	11,506,301,729
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	281,789,445	281,789,445
22	Total In Service (18 thru 21)	11,788,091,174	11,788,091,174
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	30,833,606	30,833,606
33	Total Accum Prov (equals 14) (22,26,30,31,32)	11,818,924,780	11,818,924,780

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	04/12/2018	End of 2017/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	14,566,227	27,344,254
3	Nuclear Materials	283,113,102	127,864,198
4	Allowance for Funds Used during Construction	13,338,140	7,513,920
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	311,017,469	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	62,792,088	100,864,653
9	In Reactor (120.3)	836,611,115	163,656,741
10	SUBTOTAL (Total 8 & 9)	899,403,203	
11	Spent Nuclear Fuel (120.4)	269,992,039	157,890,359
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	730,006,410	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	750,406,301	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

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	04/12/2018	End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
	16,499,518	25,410,963	2
	80,532,859	330,444,441	3
	3,832,275	17,019,785	4
			5
		372,875,189	6
			7
	163,656,741		8
	157,890,359	842,377,497	9
		842,377,497	10
	83,578,461	344,303,937	11
			12
-204,893,555	104,048,943	830,851,022	13
		728,705,601	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 2 Column: e

Transfer of nuclear materials and assemblies to stock.

Schedule Page: 202 Line No.: 3 Column: e

Transfer of nuclear materials and assemblies to stock.

Schedule Page: 202 Line No.: 4 Column: e

Transfer of nuclear materials and assemblies to stock.

Schedule Page: 202 Line No.: 8 Column: e

Transfer to reactor.

Schedule Page: 202 Line No.: 9 Column: e

Reflects nuclear fuel assemblies transferred to the spent fuel pool.

Schedule Page: 202 Line No.: 11 Column: e

Reflects nuclear fuel assemblies retired from the reactor.

Schedule Page: 202 Line No.: 13 Column: e

Includes $83,578,461 of nuclear fuel assemblies retired from the reactor and $20,470,482 of dry cask storage expenditures.

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	04/12/2018	End of 2017/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	760,394	
3	(302) Franchises and Consents	55,152,326	-909,022
4	(303) Miscellaneous Intangible Plant	352,433,607	120,437,111
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	408,346,327	119,528,089
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	27,767,621	25,798
9	(311) Structures and Improvements	489,344,236	15,702,512
10	(312) Boiler Plant Equipment	2,575,256,866	49,093,006
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	366,219,401	2,592,008
13	(315) Accessory Electric Equipment	248,962,755	2,761,197
14	(316) Misc. Power Plant Equipment	64,943,228	1,935,680
15	(317) Asset Retirement Costs for Steam Production	826,525,595	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,599,019,702	72,110,201
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	68,360,827	
19	(321) Structures and Improvements	2,933,506,683	119,722,673
20	(322) Reactor Plant Equipment	2,439,581,164	93,394,129
21	(323) Turbogenerator Units	974,103,722	114,756,333
22	(324) Accessory Electric Equipment	1,022,153,736	82,592,963
23	(325) Misc. Power Plant Equipment	555,533,788	72,406,521
24	(326) Asset Retirement Costs for Nuclear Production	876,137,782	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	8,869,377,702	482,872,619
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	2,828,917	
28	(331) Structures and Improvements	11,548,937	2,584,358
29	(332) Reservoirs, Dams, and Waterways	48,497,795	2,580,911
30	(333) Water Wheels, Turbines, and Generators	30,581,096	7,242,775
31	(334) Accessory Electric Equipment	25,619,534	1,378,109
32	(335) Misc. Power PLant Equipment	4,006,590	368,727
33	(336) Roads, Railroads, and Bridges	21,205	
34	(337) Asset Retirement Costs for Hydraulic Production	536,917	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	123,640,991	14,154,880
36	D. Other Production Plant		
37	(340) Land and Land Rights	9,994,265	
38	(341) Structures and Improvements	311,317,112	2,647,982
39	(342) Fuel Holders, Products, and Accessories	119,168,037	4,938,593
40	(343) Prime Movers	1,853,373,956	118,514,556
41	(344) Generators	466,513,220	5,409,329
42	(345) Accessory Electric Equipment	308,254,172	9,603,076
43	(346) Misc. Power Plant Equipment	44,316,257	7,364,449
44	(347) Asset Retirement Costs for Other Production	15,015,891	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,127,952,910	148,477,985
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	16,719,991,305	717,615,685

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	182,800,589	2,013,138
49	(352) Structures and Improvements	107,377,848	1,622,105
50	(353) Station Equipment	971,202,895	53,498,032
51	(354) Towers and Fixtures	61,084,937	99,075
52	(355) Poles and Fixtures	673,610,081	42,827,516
53	(356) Overhead Conductors and Devices	464,668,523	67,641,624
54	(357) Underground Conduit		23,999
55	(358) Underground Conductors and Devices	21,603,999	
56	(359) Roads and Trails	312,523	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,482,661,395	167,725,489
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	63,949,838	8,150,989
61	(361) Structures and Improvements	105,225,734	9,152,360
62	(362) Station Equipment	582,697,649	57,137,202
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	733,477,308	35,567,460
65	(365) Overhead Conductors and Devices	1,036,683,565	81,629,411
66	(366) Underground Conduit	188,322,245	5,079,491
67	(367) Underground Conductors and Devices	1,034,475,801	47,422,301
68	(368) Line Transformers	980,271,850	83,909,289
69	(369) Services	490,565,449	25,408,979
70	(370) Meters	199,687,585	23,905,931
71	(371) Installations on Customer Premises	278,952,768	16,639,520
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	191,965,375	62,458,928
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,886,275,167	456,461,861
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	7,962,878	205,609
87	(390) Structures and Improvements	141,225,733	22,064,555
88	(391) Office Furniture and Equipment	55,836,780	9,693,111
89	(392) Transportation Equipment	101,478,640	-1,916,878
90	(393) Stores Equipment	3,592,862	11,781
91	(394) Tools, Shop and Garage Equipment	49,878,447	26,605,311
92	(395) Laboratory Equipment	7,231,553	
93	(396) Power Operated Equipment	3,369,545	2,999,571
94	(397) Communication Equipment	226,154,243	4,569,498
95	(398) Miscellaneous Equipment	26,873,603	639,402
96	SUBTOTAL (Enter Total of lines 86 thru 95)	623,604,284	64,871,960
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	2,717,588	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	626,321,872	64,871,960
100	TOTAL (Accounts 101 and 106)	26,123,596,066	1,526,203,084
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	26,123,596,066	1,526,203,084

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			760,394		2
			54,243,304		3
29,498,066		236,950	443,609,602		4
29,498,066		236,950	498,613,300		5
					6
					7
			27,793,419		8
870,748	-153,591		504,022,409		9
12,137,553	-10,239,409		2,601,972,910		10
					11
462,255			368,349,154		12
2,867,644			248,856,308		13
			66,878,908		14
79,278,234	-15,071,126		732,176,235		15
95,616,434	-25,464,126		4,550,049,343		16
					17
2,389			68,358,438		18
19,734,233	-30,256	16,964,172	3,050,429,039		19
30,615,013			2,502,360,280		20
13,597,131			1,075,262,924		21
18,390,006			1,086,356,693		22
603,928			627,336,381		23
			876,137,782		24
82,942,700	-30,256	16,964,172	9,286,241,537		25
					26
			2,828,917		27
21,203			14,112,092		28
			51,078,706		29
86,849			37,737,022		30
			26,997,643		31
44,909			4,330,408		32
			21,205		33
			536,917		34
152,961			137,642,910		35
					36
-7,786			10,002,051		37
4,020,247	-2,201,159		307,743,688		38
2,049,348	-18,881		122,038,401		39
11,995,155	-572,564		1,959,320,793		40
5,519,140	-5,469		466,397,940		41
1,576,304	-35,426	-87,309	316,158,209		42
699,308	-6,937	-89,750	50,884,711		43
			15,015,891		44
25,851,716	-2,840,436	-177,059	3,247,561,684		45
204,563,811	-28,334,818	16,787,113	17,221,495,474		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
-5,227		-378,652	184,440,302		48
744,504	-169,187	-505,170	107,581,092		49
13,577,954		-432,353	1,010,690,620		50
-68,081	-1,053,755	5,508,053	65,706,391		51
8,562,391	1,053,755	-9,044,777	699,884,184		52
2,181,617		-789,962	529,338,568		53
			23,999		54
			21,603,999		55
			312,523		56
					57
24,993,158	-169,187	-5,642,861	2,619,581,678		58
					59
285		2,730,846	74,831,388		60
373,607		-154,377	113,850,110		61
4,979,297		49,585	634,905,139		62
					63
11,859,835		-291,376	756,893,557		64
14,449,240		-313,273	1,103,550,463		65
400,880		-237	193,000,619		66
4,336,861	-9,690	-1,774,381	1,075,777,170		67
11,811,064		-14,438,022	1,037,932,053		68
27,481,451		-80,116	488,412,861		69
3,455,481			220,138,035		70
3,329,836			292,262,452		71
					72
9,776,165		-263	244,647,875		73
					74
92,254,002	-9,690	-14,271,614	6,236,201,722		75
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					83
					84
					85
86,229		53,307	8,135,565		86
622,062	-106,593	5,155,295	167,716,928		87
447,173			65,082,718		88
22,110,327			77,451,435		89
857,633			2,747,010		90
163,079			76,320,679		91
451,196			6,780,357		92
49,884			6,319,232		93
3,110,571			227,613,170		94
389,578			27,123,427		95
28,287,732	-106,593	5,208,602	665,290,521		96
					97
			2,717,588		98
28,287,732	-106,593	5,208,602	668,008,109		99
379,596,769	-28,620,288	2,318,190	27,243,900,283		100
					101
					102
					103
379,596,769	-28,620,288	2,318,190	27,243,900,283		104

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	04/12/2018	End of 2017/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

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	04/12/2018	End of 2017/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	CAPE FEAR - SILVER CITY 230KV LINE	11/2009	2023	4,456,348
3	FLORENCE - MARION 230KV LINE - DILLON COUNTY	11/2009	2023	381,007
4	FLORENCE - MARION 230KV LINE - FLORENCE COUNTY	11/2009	2023	2,178,967
5	FLORENCE - MARION 230KV LINE - MARION COUNTY	11/2009	2023	440,593
6	FUQUAY BROAT STREET 115KV LINE - WAKE COUNTY	2/2017	2025	1,968,531
7	GARNER EAST 230KV SUBSTATION - WAKE COUNTY	05/2011	2023	3,610,841
8	MAYO FOSSIL - ASH POND - PERSON COUNTY	12/1983	2020	1,458,908
9	MCDOWELL STREET SUBSTATION - BUNCOMBE COUNTY	6/2016	2020	2,305,226
10	WEATHERSPOON IC - FUTURE GENERATION ADDITION	07/2008	2018	633,647
11	HARLOWE 230KV SUBSTATION	5/2016	2020	320,473
12	ASHEVILLE FLAT CREEK 115KV SUBSTATION	2/2017	2023	963,966
13	KENLY 115KV SUBSTATION	6/2011	2025	416,389
14	CARVER STREET SUBSTATION - BUNCOMBE COUNTY	7/2014	2020	5,290,411
15	JACKSONVILLE-GRANTS CREEK 230kV LINE - ONSLOW	8/2015	2020	3,498,530
16	VOLVO DEALERSHIP FUTURE USE - COUNTY BUNCOMBE	9/2016	2020	16,428,928
17	GRANTS CREEK 230KV SUBSTATION - ONSLOW COUNTY	8/2016	2020	1,344,706
18				
19				
20				
21	Other Property:			
22	Other Land and Rights < $250K (18 Items)			1,013,729
23				
24				
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46				
47	Total			46,711,200

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	04/12/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION PLANT	
2		
3	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS	15,076,506
4	KNIGHTDALE HODGE ROAD 230KV	6,227,826
5	PINE LAKE 230 KV - BANK #2 ADDITION	3,952,117
6	ELGIN 115 CAPACITY INC	3,430,559
7	EAGLE ISLAND 115 KV - CONSTRUCT BANK	2,827,383
8	DISTRIBUTION RELOCATIONS/MODIFICATIONS	2,813,677
9	DOWNTOWN RALEIGH DISTRIBUTION AUTOMATION	2,790,591
10	2017 BAYBORO DSDR WORK	2,687,806
11	BARKER SOLAR FARM, LLC	2,602,771
12	NLG - BEARD SUBSTATION 115 KV - CONVERT EASTOVER	2,378,773
13	CLEVELAND ROAD 24KV BREAKER	2,284,774
14	MANNING 115KV - REBUILD SUBSTATION	2,155,760
15	SMART GRID DEP DOWNTOWN UNDERGROUND	1,641,824
16	FLORENCE MARS BLUFF 115KV- REBUILD SUBSTATION	1,516,324
17	HOPE MILLS 230 KV - CONSTRUCT TRANSMISSION LINE	1,309,472
18	WILMINGTON SUNSET PARK 115KV - REBUILD SUBSTATION	1,202,713
19	SCOTTS HILL 230 KV - ADD 2ND FEEDER BANK	1,129,380
20	ARCHER LODGE 230KV - BANK #2 ADDITION	1,032,599
21	PROJECTS LESS THAN $1 MILLION	49,800,227
22	TOTAL DISTRIBUTION PLANT $106,861,082	
23		
24	GENERAL PLANT	
25		
26	CARY-LINE & SERVICE BUILDING	11,140,358
27	CUSTOMER CONNECT FUNDING PROJECT	7,935,135
28	MICROWAVE PROJECTS - CAROLINAS EAST	5,431,508
29	PROGRESS ENERGY CAROLINAS ACCRUAL	4,650,222
30	DRY FLY ASH RELIABILITY PROJECT	4,072,755
31	PANASONIC UNITS - CAROLINAS EAST	1,806,249
32	CAROLINAS EAST ECC - DISPATCH CONSOLE REPLACEMENT	1,755,689
33	TELECOM PROJECTS FOR POWER DELIVERY CAROLINA EAST - ELECTRIC	1,469,153
34	CAROLINA EAST - DCC CONSOLES REPLACEMENT	1,423,780
35	DEE SECURE NETWORK INFRASTRUCTURE	1,210,543
36	PROJECTS LESS THAN $1 MILLION	6,756,384
37	TOTAL GENERAL PLANT $47,651,776	
38		
39	INTANGIBLE PLANT	
40		
41	DISTRIBUTED MANAGEMENT SYSTEM PROJECT #3	8,373,260
42	DAILY RATING CHARGING ESTIMATE TOOL	8,091,255
43	TOTAL	1,422,282,356

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	04/12/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SMART GRID DISTRIBUTED MANAGEMENT SYSTEM CONSOLIDATION - TED THOMAS TOWER	4,501,891
2	CAROLINAS EMS CONSOLIDATION	3,949,595
3	SMART GRID TRANSMISSION OUTAGE APPLICATION SOFTWARE REPLACEMENT	2,889,843
4	SMART GRID CIM TO MDM INTEGRATION (DEP)	2,508,956
5	NUCLEAR MERGER PROJECT 1.1	2,343,439
6	SMART GRID DEE TRANSMISSION HEALTH RISK MANAGEMENT	2,076,969
7	SMART GRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	1,700,031
8	NUCLEAR LMS 2017	1,122,264
9	DEE ADVANCED METERING INFRASTRUCTURE OPERATIONS CENTER	1,084,664
10	PROJECTS LESS THAN $1 MILLION	3,328,289
11	TOTAL INTANGIBLE PLANT $41,970,456	
12		
13	PRODUCTION PLANT	
14		
15	ASHEVILLE COMBINED CYCLE	220,160,863
16	HARRIS POWER UPRATE	64,071,349
17	BRUNSWICK UNIT 1 MAIN TURBINE GOVERNOR CONTROL SYSTEM	62,950,438
18	HARRIS MAIN TURBINE GOVERNOR CONTROL SYSTEM	60,881,811
19	ROBINSON 115 TRANSMISSION SUT	51,404,478
20	ROBINSON UNIT 2 MAIN TURBINE GOVERNOR CONTROL SYSTEM	43,917,376
21	HARRIS VESSEL HEAD REPLACE (ALLOY 600)	40,509,838
22	DRY BOTTOM ASH CONVERSION PROJECT	34,511,068
23	ROXBORO FUEL GAS DESULFURIZATION WASTEWATER TREATMENT	31,510,801
24	BRUNSWICK UNIT 2 MAIN TURBINE GOVERNOR CONTROL SYSTEM	26,493,214
25	BRUNSWICK MELLA PLUS	17,507,144
26	BRUNSWICK UNIT 2 DISTRIBUTED I&C SYSTEM PLATFORM	17,019,554
27	HARRIS SYSTEM REPLACEMENT	12,938,696
28	BRUNSWICK UNIT 1 FW HEATER 4 & 5 LEVEL CONTROL VALVE	12,159,667
29	BRUNSWICK UNIT 1 ALT DECAY PRI HEAT	11,761,013
30	ROXBORO ESP MODIFICATIONS	11,468,282
31	BRUNSWICK UNIT 2 PPC/ERFIS SOFTWARE	10,964,825
32	BRUNSWICK UNIT 2 FW HEATER 4&5 VALVE UPGRADE MASTER	10,784,542
33	BRUNSWICK HSM PURCHASE	9,877,443
34	COAL BURNER REPLACEMENT	9,404,978
35	HARRIS PERIMETER INTRUSION DETECTION REPLACEMENT	9,341,392
36	SAFETY RELATED BATTERY CHARGERS	8,788,529
37	ROBINSON 805 DETECTION & SUPPRESSION	8,059,161
38	BRUNSWICK UNIT 1 FLEET REFUEL BRIDGE CRANE REPLACEMENT	7,888,902
39	BRUNSWICK OPEN PHASE FAULT DETECTION	7,514,196
40	BRUNSWICK UNIT 2 REACTOR REFUEL BRIDGE CRANE	7,219,357
41	MAYO STORM & PROCESS WATER REROUTE	7,034,001
42	BRUNSWICK FEEDWATER HEATER REPLACEMENT	6,931,822
43	TOTAL	1,422,282,356

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BRUNSWICK RADIO SYSTEM	6,695,327
2	BRUNSWICK UNIT 1 EMERGENCY DIESEL GENERATOR UPGRADES & REPLACEMENT	6,598,850
3	BRUNSWICK UNIT 1 CW PUMP REPLACEMENT	6,548,135
4	SAFETY RELATED CHILLERS REPLACEMENT	5,689,024
5	IMPLEMENTATION OF NEW LICENSE REQUIREMENTS	5,608,688
6	BRUNSWICK SALT WATER - PUMP REPLACEMENT	5,599,036
7	ROBINSON REPLACE OBSOLETE MOTOR CONTROL CIRCUIT BREAKERS	5,561,535
8	BRUNSWICK UNIT 1 - MARK I/MARK II HARDENED VENTS	5,419,097
9	ROBINSON TRANSMISSION	5,267,079
10	BRUNSWICK EMERGENCY WASTE PROCESSING SKID	5,173,784
11	ROBINSON START-UP TRANSFORMER	5,135,246
12	ROXBORO LINED RETENTION BASIN	4,698,626
13	HARRIS DRY WET STORAGE	4,636,357
14	ROXBORO STORM / PROCESS WATER REROUTE	4,630,625
15	BRUNSWICK PERIMETER INTRUSION DET	4,592,774
16	BRUNSWICK UNIT 1 REACTOR BUILDING ROOF DRAIN ISOLATION VALVES	4,587,259
17	MAYO CONSTRUCT NEW LINED RETENTION BASIN	4,024,980
18	BRUNSWICK UNIT 2 TRAVEL SCREEN INSRUMENT IMPROVEMENT	3,809,006
19	HARRIS FIRE DETECTION SYSTEM UPGRADE - MASTER	3,768,706
20	ROXBORO DCS EVERGREEN UP&I/O REPLACEMENT	3,697,357
21	BLEWETT FERC INSPECTION FOLLOW-UP ACTIVITIES	3,590,330
22	BRUNSWICK TRAVEL SCREEN INSTR IMPROVEMENT	3,568,365
23	BRUNSWICK SERVICE WATER PUMP REPLACEMENT	3,566,308
24	HARRIS HEATER DRAIN SYSTEM TO DCS	3,559,321
25	MAYO FUEL GAS DESULFURIZATION WASTEWATER TREATMENT	3,509,492
26	HARRIS ADDITION OF A STANDALONE SIEM	3,474,967
27	BRUNSWICK UNIT 2 REACTOR BUILDING ROOF DRAIN REPLACEMENT	3,380,064
28	HARRIS DIESEL GENERATOR MAINTENANCE BUILDING	3,327,295
29	BRUNSWICK UNIT 1 ASCOM MINI-CELL PHASE 2	3,155,633
30	HARRIS WASTE GAS COMPRESSOR UPGRADES	3,045,736
31	BRUNSWICK ENDURA PROJECT	2,967,975
32	PLANT PROCESS COMPUTER	2,942,180
33	ROBINSON TURBINES REPLACEMENT	2,853,423
34	ROBINSON PROCESS COMPUTERS	2,821,968
35	ROBINSON CONDENSATE POLISHING DCS	2,674,089
36	BRUNSWICK UNIT 1 FEEDWATER HEATER REPLACEMENT	2,439,588
37	BRUNSWICK UNIT 2 MOISTURE SEPARATER REHEATER REPLACEMENT	2,436,248
38	BRUNSWICK UNIT 1 RECIRC PUMP SEAL REPLACEMENT	2,420,855
39	ROBINSON PHASE IV DRY STORAGE	2,346,522
40	ROBINSON NON WEST MCCB REPLACEMENT	2,301,717
41	ROXBORO GENERATOR STATOR REWIND	2,295,309
42	BRUNSWICK UNIT 2 SATELITE REDUCTION	2,240,751
43	TOTAL	1,422,282,356

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	UNIT 1 EXHAUST STACK REPLACEMENT	2,199,995
2	BRUNSWICK UNIT 1 START UP AUXILIARY TRANSFROMER	2,129,122
3	BRUNSWICK HARDENED VENT MOD	2,081,078
4	CCP HF LEE POND DAM SPILLWAY INSTALLATION	2,052,280
5	ROBINSON UNDER VESSEL INSULATION	2,040,161
6	BRUNSWICK UNIT 2 TURBINE CRANE	2,005,637
7	BRUNSWICK WASTE WATER PLANT	1,976,858
8	ROXBORO DRY FLY ASH RELIABILITY PROJECT	1,932,841
9	UNIT 2 EXHAUST STACK REPLACEMENT	1,896,813
10	HCAD MAYO 2017 MITIGATION	1,879,489
11	BRUNSWICK UNIT 1 2018 SRV REBUILD/REPLACE	1,814,535
12	BRUNSWICK TRANSFER EQUIPMENT	1,730,979
13	HARRIS THERMAL CAMERA SYSTEM REPLACEMENT	1,685,555
14	2017 HARDWARE REFRESH	1,656,001
15	HF LEE CONDENSER TUBE CLEAN SYSTEM	1,613,672
16	BRUNSWICK NEW INSULATION SHOP	1,600,998
17	OUTER VBS & OCA CAMERA STANDARDIZATION	1,573,701
18	BRUNSWICK SPARE START-UP AUXILIARY TRANSFORMER	1,563,013
19	BRUNSWICK ISFSI BANKING IMPROVEMENTS	1,529,819
20	BLEWETT HYDROELECTRIC FISH PASSAGE	1,485,791
21	ROBINSON MAKE-UP WATER TREATMENT DCS	1,478,339
22	BRUNSWICK CONTROL ROOM INSTRUMENT AIR	1,473,926
23	ROBINSON OFF-SITE POWER OPEN PHASE FAULT DETECTION SYSTEM	1,408,560
24	BRUNSWICK UNIT 1 REMOTE ELECTRIC LIFT & TRAVERSING CRANE	1,323,595
25	HARRIS EMERGENCY SERVICE WATER PUMP INSTALLATION	1,321,235
26	BRUNSWICK CASWELL BEACH MICROWAVE TOWER	1,316,744
27	ROBINSON ONGOING DRY FUEL- DSC'S	1,231,459
28	TURBINE LUBE OIL CONDITIONER REPLACEMENT	1,229,941
29	ROXBORO - SMALL CAPITAL PROJECTS <50K	1,218,208
30	BRUNSWICK UNIT 2 ELECTRIC LIFT & TRANSVERSING CRANE IN EDG BUILDING	1,140,613
31	HARRIS HEEC D-WING CLASSROOM	1,105,572
32	BRUNSWICK NON DCS RECORDER	1,086,119
33	HARRIS ERFIS INVERTER 45KVA	1,080,007
34	BRUNSWICK UNIT 2 RECIRC PUMP SEAL REPLACEMENT	1,055,380
35	BRUNSWICK UNIT 2 5A AND 5B FEEDWATER HEATER ACCESS PLUGS	1,030,990
36	BRUNSWICK UNIT 1 TURBINE CRANE	1,022,330
37	ROBINSON SERVICE WATER AND DEDICATED SHUTDOWN INDICATOR PANEL	1,013,942
38	ROBINSON PENETRATION D-5 TEMP POWER	1,001,539
39	PROJECTS LESS THAN $1 MILLION	55,966,213
40	TOTAL PRODUCTION PLANT $1,103,687,417	
41		
42	TRANSMISSION PLANT	
43	TOTAL	1,422,282,356

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	04/12/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1		
2	WESTERN CAROLINAS RELIABILITY ENCHANCEMENT PROJECT- PHASE 2C	25,758,114
3	RAEFORD 230KV SUBSTATION TEMP LINE RELOCATION	16,214,330
4	ASHEVILLE COMBINED CYCLE	11,989,938
5	CASTLE HAYNE-FOLKSTONE 230KV-RELOCATE LINE	5,163,371
6	RECONDUCTOR 2.69 MI VANDERBILT-W ASHEVILLE 115KV	4,287,571
7	BRUNSWICK PLANT UNIT 1-RELOCATE LINE TERM	4,100,634
8	CAPE FEAR SILER CITY 230 (MASTER)	3,855,534
9	OTEEN-WEST ASHEVILLE 115KV LINE-RELOCATE LINE ALONG THOMPSON STREET	3,633,992
10	HENDERSON-VEPCO CARR DAM PLANT 11	3,416,209
11	RECKY MOUNT 230KV-REPLACE TRANSMISSION CLASS OIL CIRCUIT BREAKERS	3,409,184
12	WAKE 500KV - REPLACE FAILED SINGLE	3,163,030
13	HAMLET 230KV-ADD NEW BANK#3, TRANSFORMER, CONTROL BUILDING	2,324,611
14	MOBILE EQUIPMENT NEEDED FOR 2017	2,206,592
15	NOVO NORDISK NEW IND SUBSTATION	1,869,286
16	GRANTS CREEK SUB-CONSTRUCT NEW SUBSTATION AND TAPS	1,819,152
17	FLORENCE MARION 230KV LINE CONSTRUCTION	1,641,280
18	NEWPORT - HARLOWE - CONSTRUCT NEW LINE	1,627,955
19	CLEVELAND MATTHEWS ROAD 230/23KV SUBSTATION	1,621,267
20	M-AT&T COMMUNICATIONS CIRCUIT PHASE OUT PLAN	1,406,077
21	WEATHERSPOON-REAFORD -REPLACE OHGW	1,355,478
22	KNIGHTDALE HODGE ROAD 230KV	1,262,164
23	VEG MASTER- DEP	1,186,548
24	SYSTEM PROGRAM - REPLACE GE BUSHING	1,036,648
25	METHOD 230KV-REPLACE 2-3 PHASE REGULATORS	1,034,620
26	PROJECTS LESS THAN $1 MILLION	16,728,040
27	TOTAL TRANSMISSION PLANT $122,111,625	
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,422,282,356

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	11,088,222,152	11,088,222,152		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	633,577,367	633,577,367		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	10,402,780	10,402,780		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	201,153,052	201,153,052		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	845,133,199	845,133,199		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	350,134,972	350,134,972		
13	Cost of Removal	65,784,865	65,784,865		
14	Salvage (Credit)	20,903,404	20,903,404		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	395,016,433	395,016,433		
16	Other Debit or Cr. Items (Describe, details in footnote):	-32,037,189	-32,037,189		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	11,506,301,729	11,506,301,729		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,178,051,044	2,178,051,044		
21	Nuclear Production	4,596,631,914	4,596,631,914		
22	Hydraulic Production-Conventional	45,086,763	45,086,763		
23	Hydraulic Production-Pumped Storage				
24	Other Production	639,198,518	639,198,518		
25	Transmission	798,253,092	798,253,092		
26	Distribution	3,005,977,663	3,005,977,663		
27	Regional Transmission and Market Operation				
28	General	243,102,735	243,102,735		
29	TOTAL (Enter Total of lines 20 thru 28)	11,506,301,729	11,506,301,729		

Schedule Page: 219 Line No.: 8 Column: c

ARO Depreciation Expense 108/182	211,924,318
Transfer of Reserve for Externally Funded Decontaminated Decommissioning Expense	(12,529,654)
Wayne and Sutton Depreciation Amortization 403/182	(1,563,696)
Amortization of Unrecovered NBV Weatherspoon 186/403	(1,144,468)
Transmission Expansion Projects Impairment Amortization 403/107/421	778,095
Rotable Fleet Spare Reg Liability Amoritization 403/254	1,548,845
Deferred Storm Depreciation	2,132,590
Miscellaneous Depreciation Expense	7,022
	201,153,052

Schedule Page: 219 Line No.: 12 Column: c

there is a difference between the amounts for book cost of plant retired, line 12 of this page and that reported for electric plant in service, pages 204-207, column (d) is $29,461,791.

This difference is due to book cost of plant retired related to intangible plant in FERC account 303, which has a reserve account of 111100 in the amount of $29,498,066.11 and plant retired to 121000 in the amount of ($36,272.44)

Schedule Page: 219 Line No.: 16 Column: c

Coal Ash COR Reclass to 182/186	(3,505,942)
Rotable Fleet Spare Transferred Reserve	125,616
Net Gains on disposal of property	208,730
Regulatory Asset Reclass to 182	(27,528,918)
Meter Retirements to Reg Asset	328,188
Transfer From 111100	(441,161)
DEP NC Partial Settlement - Imp - Mayo Coal Unit 1	(1,086,000)
DEP NC Partial Settlement - Imp - Sutton Blackstart Common	(126,000)
Transfer from Sutton to Rockingham (DEC)	(10,823)
Miscellaneous Adjustments	(879)
	(32,037,189)

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Capitan Corporation	12/28/1931		
2	Common Stock / Equity Contribution			11,187
3	Undistributed Earnings			-7,998
4	Subtotal Capitan Corporation			3,189
5				
6	CaroFund, Inc.	8/15/1995		
7	Common Stock / Equity Contribution			1,678,508
8	Undistributed Earnings			-748,432
9	Subtotal CaroFund, Inc.			930,076
10				
11	CaroHome, LLC	4/21/1995		
12	Common Stock / Equity Contribution			69,674,735
13	Undistributed Earnings			-52,960,177
14	Subtotal CaroHome, LLC			16,714,558
15				
16	Powerhouse Square, LLC	1/16/1998		
17	Common Stock / Equity Contribution			3,054,401
18	Undistributed Earnings			-2,533,021
19	Subtotal Powerhouse Square, LLC			521,380
20				
21	Duke Energy Progress Receivables, LLC	10/16/2013		
22				
23				
24				
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33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	18,169,203

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		11,187		2
		-7,998		3
		3,189		4
				5
				6
		1,678,508		7
1,530,657		782,225		8
1,530,657		2,460,733		9
				10
				11
		69,674,735		12
266,264		-52,501,474		13
266,264		17,173,261		14
				15
				16
		3,054,401		17
-7,791		-2,540,812		18
-7,791		513,589		19
				20
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				24
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1,789,130		20,150,772		42

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	262,286,714	242,760,869	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	677,587,449	628,021,731	Generation
8	Transmission Plant (Estimated)	31,858,004	28,906,026	Transmission
9	Distribution Plant (Estimated)	71,288,844	82,205,040	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	780,734,297	739,132,797	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	163,973	134,782	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	32,787,942	35,393,695	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	1,075,972,926	1,017,422,143	

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	04/12/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	617,257.00	2,300,332	155,372.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	4,342.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	11,130.00	25,233		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	610,469.00	2,275,099	155,372.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	3,786.00		3,786.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	3,786.00			
40	Balance-End of Year			3,786.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		119		
45	Gains		42		
46	Losses				

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	04/12/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
130,958.00		130,958.00		3,404,908.00		4,439,453.00	2,300,332	1
								2
								3
				130,958.00		135,300.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						11,130.00	25,233	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
130,958.00		130,958.00		3,535,866.00		4,563,623.00	2,275,099	29
								30
								31
								32
								33
								34
								35
3,786.00		3,786.00		102,222.00		117,366.00		36
								37
								38
						3,786.00		39
3,786.00		3,786.00		102,222.00		113,580.00		40
								41
								42
								43
					28		147	44
					10		52	45
								46

Schedule Page: 228 Line No.: 1 Column: b

Begining Balance includes allowances for the Cross State Air Pollution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 29 Column: b

Ending Balance Includes allowances for the Cross State Air Pollution Rule and the Acid Rain Program

Schedule Page: 228 Line No.: 29 Column: m

Does not include $106,812,060 for renewable energy credits represented in account 0158120

Schedule Page: 228 Line No.: 39 Column: b

Represents allowances withheld in 2017 sold at auction.

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	04/12/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	33,881.00		16,469.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,486.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	10,873.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22		9,700.00			
23					
24					
25					
26					
27					
28	Total	9,700.00			
29	Balance-End of Year	14,794.00		16,469.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		378,000		
34	Gains		378,000		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

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	04/12/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						50,350.00		1
								2
								3
						1,486.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						10,873.00		18
								19
								20
								21
						9,700.00		22
								23
								24
								25
								26
								27
						9,700.00		28
						31,263.00		29
								30
								31
								32
							378,000	33
							378,000	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 1 Column: b

Begining Balance includes allowances for the Cross State Air Pollution Rule only (Annual and Seasonal).

Schedule Page: 229 Line No.: 18 Column: b

As of January 1, 2017, DE Progress is no longer subject to the requirements of the Cross State Air Pollution Rule Seasonal Nox program

Schedule Page: 229 Line No.: 29 Column: b

Ending Balance Includes allowances for the Cross State Air Pollution Rule only (Annual and Seasonal)

Schedule Page: 229 Line No.: 33 Column: c

Counterparty	Quantity	Cost of Goods Sold		Total Sales Price
Monongahela Power	1,500	0	$	7,500
Luminant Generation Company LLC	1,000	0	$	150,000
Dearborn Industrial Generation	2,000	0	$	10,000
Wolverine Power Supply Cooperative	100	0	$	500
Fathom Energy	1,000	0	$	180,000
Associated Electric Cooperative	4,000	0	$	10,000
Element Markets LLC	100	0	$	20,000
	9,700		$	378,000

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	04/12/2018	End of 2017/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	Not Applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

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	04/12/2018	End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Mayo Abandonment Loss	34,379,965	-70,766	407	70,766	330,242
22	Robinson Nuclear Plant	13,982,544		407	173,970	2,189,130
23	(7/1987 - 7/2030)					
24	Brunswick Nuclear Plant	35,107,437		407	547,327	10,216,777
25	(1/1987 - 10/2036)					
26						
27	Auth 12/22/2014 begun 1/1/2014					
28	Cape Fear Fsl Ret, Amort 10 yr	19,657,442	11,751,964	407	5,533,894	10,022,150
29	Cape Fear Fsl WS, Amor 10-18 yr	6,448,655	3,245,886	407	605,327	7,512,840
30	Lee Fossil Retail, Amort 10 yr	24,858,915	17,685,636	407	7,584,286	13,088,541
31	Lee Fossil WS, Amort 23-31 yr	8,198,992	2,492,964	407	622,504	8,484,076
32	Robinson Fsl Ret, Amort 10 yr	44,662,498	2,304,701	407	4,650,915	28,502,462
33	Robinson Fsl WS, Amort 27 yr	14,706,660	-69,969	407	417,686	13,010,430
34	Sutton Fsl Ret, Amort 10 yr	41,729,699	9,091,366	407	6,886,285	23,394,827
35	Sutton FS WS, Amort 10-27 yr	13,885,889	2,100,469	407	693,523	13,250,341
36	Weatherspoon Fsl Ret, Amort 10 yr	12,187,983	-270,335	407	2,379,397	2,473,542
37	Weatherspoon Fsl WS,Amort 22-28yr	3,903,151	-575,226	407	200,635	2,548,915
38	Cape Fear CombTur Ret, Amort 10yr	-231,651	-429,626	407	-30,272	-540,189
39	Cape Fear CombTur WS, Amort 10 yr	-74,174	-137,565	407	-11,400	-166,138
40	Lee CombustionTurb Ret,Amort 10yr	1,231,149	128,591	407	60,704	1,116,924
41	Lee CombustionTurb WS,Amort 10yr	394,210	41,174	407	-30,205	556,205
42	Morehead CombTurb Ret, Amort 10yr	-170,447	12,928	407	-17,007	-89,490
43	Morehead CombTurb WS, Amort 10yr	-54,577	4,140	407	-12,084	-2,099
44						
45	auth 11/17/2016 begun 12/1/2016					
46	Harris COLA Ret	40,630,006		407		40,630,006
47	Harris COLA WS, Amort 10 yr	7,193,008	172,787	407	722,502	6,521,661
48						
49	TOTAL	322,627,354	47,479,119		31,048,753	183,051,153

Schedule Page: 230 Line No.: 28 Column: a

Page 230b Column (a) Lines 31 - 46
Abbreviations used:
Fsl = Fossil
CombTur and CombTurb = Combustion Turbine
Ret = Retail
WS = Wholesale

Schedule Page: 230 Line No.: 28 Column: b

The amount in column (b) includes amortization of Cost of Removal through 12/31/13 totaling ($14,471,177).

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	04/12/2018	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Bennettsville System Impact	4,248	0561700		
23	Blackriver Solar System Impact	12,687			
24	Breeden Solar SIS	511			
25	Cabin Creek SIS	434			
26	Cumberland 230 kV Solar Project	369			
27	Dundarrach System Impact	82			
28	Elizabeth Farm LLC - SIS Study	38			
29	Ellington Branch Farm SIS Study	124			
30	Facility Study Q358	1,175			
31	Feasability Study	264			
32	Ford Farm Facilities Study	65			
33	Ford Farm Impact Study	20,220			
34	Fresh Air E Nash SIS Study	43			
35	Fresh Air Energy II - SIS	83			
36	Fresh Air Energy XXIII - SIS	82			
37	Fresh Air Willoughby SIS Study	43			
38	Friesian Facilties Study	173			
39	Friesian System Impact Study	10,591			
40	Highest Power SIS	65,703			

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Homer Solar Impact Study	12,779			
23	Ingram Impact Study	13,037			
24	Innovative 34 LLC FAC				
25	Innovative Solar	124			
26	Innovative Solar 129 LLC SIS Study	75			
27	Innovative Solar 129 SIS	41			
28	Innovative Solar 132 LLC SIS Study	38			
29	Juniper Solar - SIS	16			
30	Melsam Solar - SIS	16			
31	Mount Moriah Solar SIS	40			
32	Mount Olive FAC Study	293			
33	Old Hundred Solar SIS	40			
34	Old Libery Farm SIS Study	249			
35	Osborne Solar SIS	40			
36	Palmetto Solar Invenergy - Q385	13,464			
37	Paxville Farm Solar Sys Impct Stud	6,412			
38	Peacock Solar SIS	40			
39	Phobos Solar SIS Study	249			
40	Shorthorn Solar - SIS Study	43			

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	04/12/2018	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	SIS Slender Branch Solar	1,857			
23	Sonoco Affected System Study	230			
24	LLC SIS Study	43			
25	Summerton Solar SIS Study	246			
26	Swamp Fox	72			
27	System impact - Fair Bluff Solar	976			
28	System Impact - NTE Carolina Solar	1,230			
29	System Impact Study for Q370	4,800			
30	Trent River Solar SIS Study	115			
31	Virginia Line Solar - SIS	20			
32	Bay Tree Impact Study	16,612			
33	Hobkirk Hill Farm	43			
34	SIS Crooked Run Solar	14,016			
35					
36					
37					
38					
39					
40					

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	04/12/2018	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Fuel Assets (NC Docket E-2, Sub 1031)	163,800	45,951,221	various	35,406,455	10,708,566
2						
3	SFAS 158 Regulatory Assets (NC Docket E-100,	423,206,985	44,575,411	various	38,368,248	429,414,148
4	Sub 913)					
5						
6	Grid South Deferral SC	3,676,168		various		3,676,168
7						
8	Deferred Fuel Clause: North Carolina Retail	16,111,823	164,160,646	254,557	59,767,369	120,505,100
9	(NC Docket E-2, Sub 1146)					
10						
11	Deferred Fuel Clause: South Carolina Retail	9,056,277	15,685,666	254,557	15,142,246	9,599,697
12	(SC Docket 2017-1-E)					
13						
14	NC REPS Deferral (NC Docket E-2, Sub 1032)	(199,621)	2,633,470	various	5,129,224	-2,695,375
15						
16	SFAS 143 Regulatory Assets (NC Docket E-2, Sub 826;	289,851,494	173,618,878	various	89,256,045	374,214,327
17	SC Docket 2003-84-E)					
18						
19	SFAS 109 Regulatory Assets	300,278,399	328,962,519	various	467,058,282	162,182,636
20						
21	Accrued Vacation (NC Docket E-2, Sub 859)	37,760,331	4,410,589	various		42,170,920
22						
23	Gas Pipeline Upgrade	504,779		186,547	54,570	450,209
24	(Amortized over 25 years, ending 2026)					
25						
26	Pollution Control SC (Docket No. 2008-435-E)	35,786,934	10,321,784	407	13,430,942	32,677,776
27						
28	DSM/EE Deferral NC (NC Docket E-2, Sub 1030)	228,555,643	119,947,672	407,408	111,944,370	236,558,945
29						
30	DSM/EE Deferral SC(Docket No. 2013-76-E)	34,247,580	19,811,807	407,408	26,129,966	27,929,421
31						
32	Wayne County Plant Deferred Costs NC	6,338,671	5,188,666	various	9,362,801	2,164,536
33	(NC Docket E-2, Sub 1026)					
34	(Amortized over 5 years, beginning 2013)					
35						
36	Wayne County Plant Deferred Costs SC	20,538,745	9,315,783	various	9,239,008	20,615,520
37	(SC Docket 2013-155-E)					
38						
39	Rate Case Cost Deferral (NC Docket E-2, Sub 1023)	843,772		928	595,605	248,167
40	(Amortized over 5 years, beginning 2013)					
41						
42	Rate Case Cost Deferral (SC Docket 2016-227-E)		145,288	928	22,940	122,348
43						
44	TOTAL	3,099,341,503	1,933,647,699		1,613,058,089	3,419,931,113

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Nuclear Levelization Deferral NC and SC	38,325,901	169,508,059	various	172,496,641	35,337,319
2	(NC Docket E-2, Sub 1023) (SC Docket 2016-227-E)					
3	(Amortized over 18-24 mths, based on cycle)					
4						
5	Sutton Plant Deferred Costs SC	10,926,718	3,271,676	various	3,452,756	10,745,638
6	(SC Docket 2013-472-E)					
7						
8	Fukushima/Cyber Security Deferral SC	4,099,635	874,032	various	244,352	4,729,315
9	(SC Docket 2013-472-E)					
10						
11	Coal Ash Basin ARO Deferral NC	1,554,502,022	616,615,733	various	437,813,561	1,733,304,194
12	(NC Coal Ash Management Act of 2014)					
13						
14	Interest rate Swap	5,574,632	19,062,281	various	19,080,767	5,556,146
15	(NC Docket E-2, Sub 1006; SC Docket 2015-95-E)					
16						
17	SC Storm Costs Deferral	14,713,413	63,347,690	various	4,880,163	73,180,940
18	(SC Docket 2014-482-E)					
19						
20	NCEMPA Purchase Deferral NC	43,024,403	88,023,712	various	84,375,219	46,672,896
21	(NC Docket E-2, Sub 1143)					
22						
23	NCEMPA Purchase Deferral SC	16,881,000	605,890	various	7,271,013	10,215,877
24	(SC Docket 2016-227-E)					
25						
26	SC DERP Deferral	557,517	7,697,812	various	1,214,751	7,040,578
27	(SC Docket 2015-1-E)					
28						
29	Regulatory Fee Deferral NC	1,127,493	834,017	928	165,999	1,795,511
30	(NC Docket M-100, Sub 142)					
31						
32	Deferred VOP Costs	2,886,989	577,397	920	1,154,796	2,309,590
33	(SC Docket 2016-227-E)					
34						
35	DEP SC COR Giveback (SC Docket 2016-227-E)		18,500,000	407		18,500,000
36						
37						
38						
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40						
41						
42						
43						
44	TOTAL	3,099,341,503	1,933,647,699		1,613,058,089	3,419,931,113

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	04/12/2018	End of 2017/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Unrecovered Plant	11,570,243	328,188	403/426	11,570,243	328,188
2						
3	Interest Rate Hedges	59,283,968		427	13,241,959	46,042,009
4						
5	Accounts in Process of Reclass	132,917	144,695	Various	9,362	268,250
6						
7	Deferred Rate Case Expenses	513,693	4,467,861	Various	722,369	4,259,185
8						
9	Gas Pipeline Charges	4,448,835		547	480,955	3,967,880
10	2001-2026 amortization period					
11						
12	Workers Comp Insurance Reimb	3,836,590		228.2	676,819	3,159,771
13						
14	Fukushima Pooled Inventory	1,805,782		232		1,805,782
15						
16	Cost of Removal Settlement - NC	20,000,000		Various		20,000,000
17						
18	Deferred Coal Ash Remediation	265,354,126	153,007,920	Various	176,645,928	241,716,118
19						
20	NCEMPA SC Equity Reserve	-9,401,000	6,187,595	407	714,617	-3,928,022
21						
22	Deferred Storm Costs	133,127,511	83,651,382	421/566	134,871,071	81,907,822
23						
24	Solar Equity Reserve	-749,922	2,264,383	421	6,913,945	-5,399,484
25						
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45						
46						
47	Misc. Work in Progress	453,415				174,127
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	490,376,158				394,301,626

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5			
6			
7	Other	2,083,860,008	1,775,392,682
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,083,860,008	1,775,392,682
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,083,860,008	1,775,392,682

Notes

Schedule Page: 234 Line No.: 18 Column: c

The ending balance reflects the following impacts of the Tax Cuts and Jobs Act:

(a)$764,970,758 decrease due to the estimated remeasurement of the existing deferred tax assets to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent.

(b)$414,837,655 increase due to the gross up recorded on estimated net excess deferred federal income taxes. The estimated net excess deferred federal income taxes resulted from the remeasurement of existing net deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent.

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Not Applicable			
2				
3				
4				
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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	04/12/2018	End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
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						4
						5
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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	04/12/2018	End of 2017/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid-In Capital:	
2	1984 Expenses	-15,569
3	1985 Expenses	-53,827
4	1986 Expenses	-59,469
5	2011 Expenses	4,559,631
6	CP&L Customer Stock Ownership Plan:	
7	1984 Expenses	-9,575
8	1985 Expenses	-2,990
9	CP&L Stock Purchase Savings Plan - 1985 Expenses	-32,166
10	Issuance of Common Stock - 1985 Expenses	-141,781
11	CP&L Common Stock Sale to Retail Customers:	
12	1986 Expenses	-9,052
13	1988 Expenses	-9,548
14	CP&L Common Stock Split - 1993 Expenses	-456,341
15	Issuance of Common Stock - 1999 Expenses	-3,511
16	Listing Additional Shares on the New York Stock Exchange:	
17	2000 Expenses	-21,961
18	Transfer of Board of Directors' Compensation Plan - 2000	4,690,089
19	Reclass Equity Accounts - 2001	115,000,000
20	Contributions Related to Employee Stock Ownership Plan:	
21	2000	2,977,924
22	2001	22,585,247
23	2002	25,268,396
24	2003	19,838,656
25	2004	22,183,955
26	2005	19,528,622
27	2006	18,781,253
28	2007	20,167,207
29	2008	16,057,376
30	2009	10,138,259
31	2010	9,693,593
32	North Carolina Natural Gas Divestiture - 2003	3,297,692
33	Stock Options Income Tax - 2004	199,761
34	Non-Cash Dividend to Parent - 2005	-17,069,331
35	Stock Based Compensation:	
36	2005	3,378,817
37	2006	10,150,080
38	2007	24,072,823
39	2008	12,752,805
40	TOTAL	2,784,376,571

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Stock Based Compensation:	
2	2009	15,355,354
3	2010	11,429,228
4	2011	14,295,722
5	2012	11,050,101
6	2015 Conversion of Duke Energy Progress to a limited liability company	1,759,809,101
7	Capital Infusion from Duke Energy Corporation	625,000,000
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40	TOTAL	2,784,376,571

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	04/12/2018	End of 2017/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
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22	TOTAL	

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - First Mortgage and Pollution Control Bonds:		
2			
3	4.000% Wake 2002 Pollution Control Bonds Due 6/1/2041	48,485,500	603,686
4			
5	5.3% Series Due 1/15/2019	600,000,000	3,900,000
6			552,000 D
7	8.625% Series Due 9/15/2021	100,000,000	564,887
8			375,000 D
9	3% Series Due 9/15/2021	500,000,000	3,250,000
10			860,000 D
11	2.8% Series Due 5/15/2022	500,000,000	3,900,000
12			1,125,000 D
13	6.125% Series Due 9/15/2033	200,000,000	2,048,641
14			3,104,000 D
15	5.7% Series Due 4/1/2035	200,000,000	1,928,655
16			518,000 D
17	6.3% Series Due 4/1/2038	325,000,000	2,843,750
18			581,750 D
19	4.1% Series Due 5/15/2042	500,000,000	5,025,000
20			2,480,000 D
21	4.1% Series Due 3/15/2043	500,000,000	4,330,566
22			3,675,000 D
23	4.375% Series Due 3/30/2044	400,000,000	3,563,688
24			3,500,000 D
25	4.150% Series Due 12/1/2044	500,000,000	4,443,471
26			4,375,000 D
27	Floating Rate Series Due 3/6/2017 (1.146% at 3/31/2017)		1,039,782
28			875,000 D
29	Floating Rate Series Due 11/20/2017 (1.516% at 11/30/2017)		827,369
30			700,000 D
31	3.25% Series Issued 8/13/2015 Due 8/15/2025	500,000,000	2,812,775
32			3,250,000 D
33	TOTAL	7,273,485,500	98,575,403

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.2% Series Issued 8/13/2015 Due 8/15/2045	700,000,000	6,027,165
2			6,125,000 D
3	3.7% Series Issued 9/16/2016	450,000,000	3,836,700
4			3,937,500 D
5			
6	3.60% Series Issued 9/5/2017 Due 9/15/2047	500,000,000	4,247,291
7			1,050,000 D
8	Floating Rate Series Due 9/8/2020 (1.657% at 12/31/2017)	300,000,000	4,375,000 D
9			D
10	SUBTOTAL - Account 221	6,823,485,500	96,651,676
11			
12	Account 222 - Reacquired Bonds		
13	None		
14			
15	Account 223 - Advances to Associated Companies:		
16	Commercial Paper Series Due 1/30/2020 (1.570% at 12/31/2017)	150,000,000	
17			
18	SUBTOTAL - Account 223	150,000,000	
19			
20	Account 224 - Other Long-Term Debt:		
21	DEP Receivables 300M Due 2/12/2019	300,000,000	1,923,727
22			
23	SUBTOTAL - Account 224	300,000,000	1,923,727
24			
25			
26			
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30			
31			
32			
33	TOTAL	7,273,485,500	98,575,403

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	04/12/2018	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
02/06/2002	06/01/2041	06/01/2013	06/01/2041	48,485,000	1,939,400	3
						4
01/15/2009	01/15/2019	01/15/2009	01/15/2019	600,000,000	35,364,000	5
						6
10/02/1991	09/15/2021	09/15/1991	09/15/2021	100,000,000	8,625,000	7
						8
09/15/2011	09/15/2021	09/15/2011	09/15/2021	500,000,000	18,181,015	9
						10
05/15/2012	05/15/2022	05/15/2012	05/15/2022	500,000,000	18,284,894	11
						12
09/11/2003	09/15/2033	09/11/2003	09/15/2033	200,000,000	12,250,000	13
						14
03/22/2005	04/01/2035	03/22/2005	04/01/2035	200,000,000	11,400,000	15
						16
03/13/2008	04/01/2038	03/13/2008	04/01/2038	325,000,000	21,658,048	17
						18
05/15/2012	05/15/2042	05/15/2012	05/15/2042	500,000,000	20,500,000	19
						20
03/12/2013	03/15/2043	03/15/2013	03/15/2043	500,000,000	21,529,000	21
						22
03/06/2014	03/30/2044	03/06/2014	03/30/2044	400,000,000	17,500,000	23
						24
11/20/2014	11/20/2014	11/20/2014	12/01/2044	500,000,000	20,750,000	25
						26
03/06/2014	03/06/2017	03/06/2014	03/06/2017		509,507	27
						28
11/20/2014	11/20/2017	11/20/2014	11/20/2017		2,404,025	29
						30
8/13/2015	8/15/2025	8/13/2015	8/15/2025	500,000,000	16,250,000	31
						32
				7,273,485,000	286,521,162	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
8/13/2015	8/15/2045	8/13/2015	8/15/2045	700,000,000	29,400,000	1
						2
9/16/2016	10/15/2046	9/16/2016	10/15/2046	450,000,000	16,650,000	3
						4
						5
9/8/2017	9/15/2047	9/8/2017	9/15/2047	500,000,000	5,650,000	6
						7
9/5/2017	9/8/2020	9/5/2017	9/8/2020	300,000,000	1,478,026	8
						9
				6,823,485,000	280,322,915	10
						11
						12
						13
						14
						15
12/9/2015	1/30/2020	12/9/2015	1/30/2020	150,000,000	667,352	16
						17
				150,000,000	667,352	18
						19
						20
12/20/2013	2/12/2019	12/20/2013	2/12/2019	300,000,000	5,530,895	21
						22
				300,000,000	5,530,895	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				7,273,485,000	286,521,162	33

Schedule Page: 256 Line No.: 1 Column: a

All First Mortgage Bonds were pledged to The Bank of New York Mellon, as Trustee. In general, first mortgage bonds were pledged to finance the construction of various plant facilities, retirement of short or long-term debt and general corporate purposes.

All Pollution Control Bonds were pledged to The Bank of New York Mellon, as Trustee, to finance the retirement of previously issued pollution control bonds outstanding, which were issued to finance the construction of pollution control facilities at the Company’s Harris, Mayo and Roxboro plants.

Schedule Page: 256.1 Line No.: 3 Column: a

Bond issuance approved pursuant to NCUC order issued in Docket Number E-2, Sub 1049 on July 30, 2014 and PSCSC Docket 2014-300-E on August 22, 2014.

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	715,397,849
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Notes for Detailed List	906,385,524
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-190,987,675
28	Show Computation of Tax:	
29		
30	35% of Line 27	-66,845,686
31	Prior Year Federal Tax Adjustment - Primarily Prior Year Tax True-Ups	-27,517,811
32		
33	Total Federal Income Tax	-94,363,497
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 20 Column: b

Provision for Deferred Income Taxes	(386,955,745)
Provision for Current Federal Income Taxes	94,363,497
Investment Tax Credit Amortization	3,380,372
COLI Policy Gains/Death Benefits	4,115,019
Book Depreciation/Amortization	(635,509,676)
Tax Depreciation/Amortization	1,252,204,342
Tax Gains/Losses (Cost of Removal)	67,000,000
Equipment/T&D Repairs	299,000,000
AFUDC Equity	47,441,028
AFUDC Interest	20,954,034
Contributions in Aid of Construction	(10,725,739)
Tax Interest Capitalized	(37,705,675)
Nuclear Fuel Book Burned	(201,901,964)
Self Developed Software	52,184,190
Non-Cash Overhead Basis Adjustment	(11,064,410)
Unbilled Revenue	(958,901)
Deferred Fuel	128,935,818
Benefits Accruals	42,094,720
Severance Accrual	5,028,493
Deferred Compensation	4,028,185
Storm Cost Deferral	2,598,278
Charitable Contribution Accruals	10,490,919
NC REC Liability	(41,645,829)
End of Life Nuclear Fuel Cost Reserve	(8,070,085)
Lawsuit Contingency	(5,918,104)
Impairment	(12,454,513)
SC Distributive Energy Resource Program	6,483,061
DEP SC COR Giveback	18,500,000
Non-Qualified Nuclear Decommissioning Contributions/Earnings	12,760,651
Coal Ash Spend, Net of Capitalized Portion	10,232,857
Regulatory Asset - Deferred Plant Costs	(14,843,281)
Regulatory Asset - FAS 158	20,705,318
Regulatory Asset - Nuclear Levelization	(2,988,582)
Regulatory Asset - Save-A-Watt Program	1,685,144
Regulatory Asset - Plant Related Retirements	17,842,912
Regulatory Asset - NCEMPA Purchase Deferrals	2,456,348
Net Operating Loss Utilization/Deferral	158,910,166
Other Items	(6,267,324)
Total Differences Between Book & Taxable Income	**906,385,524**

Allocations of consolidated tax liability are based on the percentage method of allocation under Treasury Regulation Section 1.1502-33(d)(3), with a fixed percentage of 100 percent, in conjunction with the income method under Treasury Regulation Section 1.1552-1(a)(1).

For members of the affiliated group, see corporations controlled by respondent, page 103.

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	04/12/2018	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income	88,992,658		-94,363,497	53,382,074	62,467,233
3	Unemployment	3,018		-623,727	241,278	865,761
4	Highway Use			45,282	45,282	
5	Social Security	6,654,754		37,753,738	38,812,790	220,572
6	SUBTOTAL	95,650,430		-57,188,204	92,481,424	63,553,566
7						
8	NORTH CAROLINA:					
9	Income	2,310,436		2,351,775	6,077,869	1,415,658
10	Property	428,412		64,431,555	47,687,601	-163,777
11	Franchise	208,218		15,568,264	13,000,024	
12	Unemployment	6,713		61,573	67,486	
13	Municipal License	-152,338		365,611	365,611	
14	Other Taxes			308,536	308,536	
15	SUBTOTAL	2,801,441		83,087,314	67,507,127	1,251,881
16						
17	SOUTH CAROLINA:					
18	Income	-4,262		5,813	-308,988	-28,551
19	Property	97		33,386,855	153,419	-218,192
20	Public Utility Corp Licenses	49,875		7,522		
21	Unemployment	1,617		89,975	76,997	-13,343
22	KWH Electric Power			2,107,440	2,107,440	
23	Other Taxes			21,086	21,086	
24	Municipal License	7,019,625			9,647,777	10,200,503
25	Privilege License	-316,635		1,768,252	2,255,570	
26	SUBTOTAL	6,750,317		37,386,943	13,953,301	9,940,417
27						
28	OTHER STATES:					
29	FIN 48	1,370,704				
30	Unemployment	-670		5,139	4,469	
31	Other Taxes			-102	-102	
32	Franchise			311,028	311,028	
33	SUBTOTAL	1,370,034		316,065	315,395	
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	106,572,222		63,602,118	174,257,247	74,745,864

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	04/12/2018	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
3,714,320		-91,946,206			-2,417,291	2
3,774		-623,727				3
		45,282				4
5,816,274		37,753,738				5
9,534,368		-54,770,913			-2,417,291	6
						7
						8
		2,508,953			-157,178	9
17,008,589		62,413,522			2,018,033	10
2,776,458		15,568,264				11
800		61,573				12
-152,338		365,611				13
		308,354			182	14
19,633,509		81,226,277			1,861,037	15
						16
						17
281,988		53,351			-47,538	18
33,015,341		33,332,099			54,756	19
57,397		7,522				20
1,252		89,975				21
		2,107,440				22
		21,086				23
7,572,351						24
-803,953		1,768,252				25
40,124,376		37,379,725			7,218	26
						27
						28
1,370,704						29
		5,139				30
		-102				31
		311,028				32
1,370,704		316,065				33
						34
						35
						36
						37
						38
						39
						40
70,662,957		64,151,154			-549,036	41

Schedule Page: 262 Line No.: 2 Column: f

Offset to account 146	(22,133,661)
Offset to account 143	84,600,894
	62,467,233

Schedule Page: 262 Line No.: 3 Column: f

Offset to account 242	826,122
Offset to account 254	39,639
	865,761

Schedule Page: 262 Line No.: 5 Column: f

Offset to account 242	220,055
Offset to account 254	517
	220,572

Schedule Page: 262 Line No.: 9 Column: f

Offset to account 146 1,415,658

Schedule Page: 262 Line No.: 10 Column: f

Offset to account 182 (163,777)

Schedule Page: 262 Line No.: 18 Column: f

Offset to account 146 (28,551)

Schedule Page: 262 Line No.: 19 Column: f

Offset to account 182 (218,192)

Schedule Page: 262 Line No.: 21 Column: f

Offset to account 241 (13,343)

Schedule Page: 262 Line No.: 24 Column: f

Offset to account 142 10,200,503

Schedule Page: 262 Line No.: 29 Column: a

Prior year end of year balances that were reported on multiple rows are being consolidated on one row for reporting going forward.

Schedule Page: 262 Line No.: 30 Column: a

Prior year end of year balances that were reported on multiple rows are being consolidated on one row for reporting going forward.

Schedule Page: 262 Line No.: 34 Column: a

Per the instructions for page 262-263, which state, “Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged”, the following amounts have been excluded from Taxes Accrued balances:

Sales and Use Tax Payable – 1,254,199 Excluded from Balance At Beginning Of Year (column b)
Sales and Use Tax Payable – 796,280 Excluded from Balance At End Of Year (column g)

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	04/12/2018	End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	3,442,626			411.4	590,597	
4	7%						
5	10%	56,528,016			411.4	2,218,612	
6	6%	134,099			411.4	4,369	
7		86,294,907				566,794	311,633
8	TOTAL	146,399,648				3,380,372	311,633
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	8%	6,167,834			411.4	566,794	
11	30%	80,127,073					311,633
12	TOTAL	86,294,907				566,794	311,633
13							
14							
15							
16							
17							
18							
19							
20							
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46							
47							
48							

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	04/12/2018	End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
2,852,029	37-58 Years		3
			4
54,309,404	37-58 Years		5
129,730	37-58 Years		6
86,039,746	37-58 Years		7
143,330,909			8
			9
5,601,040	37-58 Years		10
80,438,706			11
86,039,746			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
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			32
			33
			34
			35
			36
			37
			38
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			40
			41
			42
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			47
			48

Schedule Page: 266 Line No.: 7 Column: g

The deferral of $23,352,299 reported for 2016 represented an estimate of the 30% investment tax credit for the Elm City Solar Project. During 2017, the 2016 Federal Tax Return was filed and the actual amount of the credit was lower than originally estimated by $1,306,989. In addition, the 2016 Federal Tax Return included additional cost basis that was allocated to the solar projects originally reported on the 2015 Federal Tax Return (Fayetteville, Warsaw and Jacksonville). This resulted in an increase in the investment tax credits of $1,618,622. The net adjustment was an increase of $311,633.

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	04/12/2018	End of 2017/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Credit - Smart Grid	1,534,126	143.6			1,534,126
2						
3	NC Eastern Municipal Power					
4	Agency					
5						
6	CATV Pole Rent	3,955,671	Various	4,012,424	3,862,415	3,805,662
7						
8	Environmental Reserve for					
9	Manufactured Gas Plants	412,645	462.5	256,217	181,816	338,244
10						
11	NC Tax Rate Change	24,737,560	Various	224,338,347	204,644,358	5,043,571
12						
13						
14	Tariff Admin	195,000	None			195,000
15						
16	Cash Collections	3,264,320	Various	4,233,587	969,267	
17						
18	Piedmont Natural Gas Merger					
19	Donation Commitment	22,125,000	426.1	7,375,000		14,750,000
20						
21	Minor Items	79,271	Various	156,822	200,737	123,186
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	56,303,593		240,372,397	209,858,593	25,789,789

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

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	04/12/2018	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							21

NOTES (Continued)

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	04/12/2018	End of 2017/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	3,902,880,700	658,967,136	474,480,418
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,902,880,700	658,967,136	474,480,418
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	3,902,880,700	658,967,136	474,480,418
10	Classification of TOTAL			
11	Federal Income Tax	3,607,488,881	655,268,243	471,235,191
12	State Income Tax	295,391,819	3,698,893	3,245,227
13	Local Income Tax			

NOTES

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
7,350,693	50,895,453	182/253/254	1,504,289,059	254	15,822,810	2,555,356,409	2
							3
							4
7,350,693	50,895,453		1,504,289,059		15,822,810	2,555,356,409	5
							6
							7
							8
7,350,693	50,895,453		1,504,289,059		15,822,810	2,555,356,409	9
							10
7,090,872	50,966,798		1,470,774,614		15,246,994	2,292,118,387	11
259,821	-71,345		33,514,445		575,816	263,238,022	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: g

182 - Regulatory Assets	$64,389,347(b)
253 - North Carolina Excess Deferred Income Taxes	3,122,620
254 - North Carolina Excess Deferred Income Taxes	17,905,734
254 - Federal Excess Deferred Income Taxes	1,418,871,357(a)
Rounding	1
Total	$1,504,289,059

(a)Estimated remeasurement of existing deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act. Where the reduction in the accumulated deferred tax liability is expected to be returned to customers in future rates, the estimated remeasurement has been deferred as a net regulatory liability.

(b)Includes the impact of the estimated remeasurement of existing deferred taxes to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act.

Schedule Page: 274 Line No.: 2 Column: i

254 - Other Regulatory Liabilities $15,822,810 (a)

(a)Includes the impact of the estimated remeasurement of existing deferred taxes to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act.

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	04/12/2018	End of 2017/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other	1,504,298,151	349,413,547	40,971,608
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,504,298,151	349,413,547	40,971,608
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,504,298,151	349,413,547	40,971,608
20	Classification of TOTAL			
21	Federal Income Tax	1,375,657,819	327,963,997	42,660,896
22	State Income Tax	128,640,332	21,449,550	-1,689,288
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
874	21,014,328	See Foot	689,216,550			1,102,510,086	3
							4
							5
							6
							7
							8
874	21,014,328		689,216,550			1,102,510,086	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
874	21,014,328		689,216,550			1,102,510,086	19
							20
874	20,991,864		668,127,811			971,842,119	21
	22,464		21,088,739			130,667,967	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: g

146 - Intercompany Transactions	$ 154,397
182 - Regulatory Assets	73,706,416(b)
253 - North Carolina Excess Deferred Income Taxes	1,544,776
254 - North Carolina Excess Deferred Income Taxes	8,858,055
254 - Federal Excess Deferred Income Taxes	604,952,906(a)
Total	$689,216,550

(a)Estimated remeasurement of existing deferred tax liabilities to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act. Where the reduction in the accumulated deferred tax liability is expected to be returned to customers in future rates, the estimated remeasurement has been deferred as a net regulatory liability.

(b)Includes the impact of the estimated remeasurement of existing deferred taxes to reflect the reduction in the federal corporate tax rate from 35 percent to 21 percent due to the Tax Cuts and Jobs Act.

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	04/12/2018	End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	EPA Emission Allowances (NC Docket E-2, Sub 1023)	3,677,745	407	3,051,823	416,762	1,042,684
2	Amortized over 5 yrs beginning June, 2013.					
3						
4	SFAS 109 Regulatory Liabilities	142,687,520	various	252,689,787	180,007,236	70,004,969
5						
6	Deferred Fuel Clause: North Carolina Retail	63,848,330	182	165,907,174	103,227,825	1,168,981
7	(NC Docket E-2, Sub 1146)					
8						
9	Deferred Fuel Clause: South Carolina Retail		182			
10	(SC Docket 2017-1-E)					
11						
12	DOE Refund Deferral (NC Docket E-2, Sub 1023)	4,248,461	various	3,186,346	637,269	1,699,384
13	Amortized over 7 yrs ending 2018.					
14						
15	SFAS 143 Regulatory Liabilities (NC Docket E-2,	15,264,104	various			15,264,104
16	Sub 826; SC Docket 2003-84-E)					
17						
18	Nuclear Decommissioning Trust - Unrealized Gains	681,097,745	128,182	99,908,166	392,060,452	973,250,031
19	(NC Docket E-2, Sub 826; SC Docket 2003-84-E)					
20						
21	NC REPS Deferral (NC Docket E-2 Sub 1032)	86,628,944	various	18,675,790	42,737,426	110,690,580
22						
23	Nuclear Fuel Last Core Reserve	28,917,804	various		8,070,085	36,987,889
24	(NC Docket E-2, Sub 1023)					
25						
26	Harris Land Sale Gains	2,180,876	407	1,539,441		641,435
27	(NC Docket E-2, Sub 1023)					
28	Amortized over 5 yrs beginning June 2013.					
29						
30	NC Tax Rate Change	150,465,625	various	232,889,282	227,548,795	145,125,138
31	(NC Docket E-2, Sub 1046)					
32						
33	OPEB Reg Liability	83,101	various	577,968	425,902	-68,965
34						
35	NCDT Overfund Liability					
36	(SC Docket 2013-472 E)					
37						
38	Open Interest rate Swap	46,919,677	various	143,206,531	96,286,854	
39	(NC Docket E-2, Sub 1006; SC Docket 2015-95-E)					
40						
41	TOTAL	1,228,887,118		983,034,566	2,912,511,081	3,158,363,633

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	04/12/2018	End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Rotable Fleet Spare	2,867,186	various	1,548,845	645,665	1,964,006
2	(NC Docket E-2, Sub 998A)					
3						
4	Income Tax Reform		various	59,853,413	1,860,446,810	1,800,593,397
5						
6						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,228,887,118		983,034,566	2,912,511,081	3,158,363,633

Schedule Page: 278 Line No.: 23 Column: a

To establish an end of life reserve for nuclear fuel and related materials and supplies per NCUC Docket E-2, Sub 1023 order dated May 30, 2013.

Schedule Page: 278 Line No.: 26 Column: a

To defer gains on sale of land at Harris Nuclear Plant and to amortize previous gains on Harris land sales per NCUC Docket E-2, Sub 1023 order dated May 30, 2013. Duke Energy Progress will amortize previous gains at $1.5 million per year over 5 years beginning June, 2013.

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	04/12/2018	End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,818,028,091	1,917,409,351
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,184,079,182	1,240,031,513
5	Large (or Ind.) (See Instr. 4)	623,850,424	637,611,854
6	(444) Public Street and Highway Lighting	19,637,514	20,345,197
7	(445) Other Sales to Public Authorities	81,095,376	84,996,646
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,726,690,587	3,900,394,561
11	(447) Sales for Resale	1,257,931,458	1,234,198,215
12	TOTAL Sales of Electricity	4,984,622,045	5,134,592,776
13	(Less) (449.1) Provision for Rate Refunds		-699,832
14	TOTAL Revenues Net of Prov. for Refunds	4,984,622,045	5,135,292,608
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,481,360	7,752,736
17	(451) Miscellaneous Service Revenues	7,667,672	7,790,254
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	41,498,063	37,054,303
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	9,560,739	10,316,292
22	(456.1) Revenues from Transmission of Electricity of Others	73,854,633	67,549,828
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	141,062,467	130,463,413
27	TOTAL Electric Operating Revenues	5,125,684,512	5,265,756,021

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	04/12/2018	End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
17,372,065	17,946,817	1,309,968	1,291,742	2
				3
13,945,850	14,094,399	231,945	229,002	4
10,417,125	10,266,479	4,122	4,136	5
80,125	87,536	1,456	1,537	6
1,454,845	1,472,596	5	5	7
				8
				9
43,270,010	43,867,827	1,547,496	1,526,422	10
23,552,726	25,184,327	14	15	11
66,822,736	69,052,154	1,547,510	1,526,437	12
				13
66,822,736	69,052,154	1,547,510	1,526,437	14

Line 12, column (b) includes $ 17,834,534 of unbilled revenues.

Line 12, column (d) includes 216,632 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

Includes $6,302,524 of service charges and $1,365,148 of miscellaneous service revenue.

Schedule Page: 300 Line No.: 17 Column: c

Includes $6,096,168 of service charges and $1,694,086 of miscellaneous service revenue.

Schedule Page: 300 Line No.: 21 Column: b

Includes $6,255,175 of non-refundable liquidated damages and penalties from new solar interconnect agreements, $2,240,720 of contributions in aid of construction revenue,and $950,992 of electric revenue from cogeneration/small power producers.

Schedule Page: 300 Line No.: 21 Column: c

Includes $2,692,558 of coal blended savings as a result of the merger with Duke Energy, $5,873,689 of contributions in aid of construction revenue, $765,951 of compensation for service to others revenue,$693,106 of electric revenue from cogeneration/small power producers and coal inventory rider credits $(196,040).

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	04/12/2018	End of 2017/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
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37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential					
2	RES	17,141,893	1,760,538,271	1,306,426	13,121	0.1027
3	SLR	16,824	6,248,752	3,542	4,750	0.3714
4	ALS	69,449	20,771,847			0.2991
5	Unbilled	143,899	12,673,427			0.0881
6	TOTAL RESIDENTIAL	17,372,065	1,800,232,297	1,309,968	13,261	0.1036
7						
8	Commercial					
9	ALS	253,032	51,537,078			0.2037
10	APH-TES	2,336	140,282	3	778,667	0.0601
11	CH-TOUE	7,598	1,044,443	227	33,471	0.1375
12	CS	2,382	349,653	90	26,467	0.1468
13	LGS	1,258,458	86,004,688	98	12,841,408	0.0683
14	MGS	2,732,138	255,869,864	18,383	148,623	0.0937
15	SFLS	1,304	229,418	92	14,174	0.1759
16	SGS	9,564,312	749,799,279	210,518	45,432	0.0784
17	SI	66,001	6,956,556	1,136	58,099	0.1054
18	SLS	12,178	4,067,919	1,164	10,462	0.3340
19	TFS	173	32,328	107	1,617	0.1869
20	TSS	250	21,238	36	6,944	0.0850
21	GS	3,133	403,387	91	34,429	0.1288
22	Unbilled Revenue	42,555	3,415,709			0.0803
23	TOTAL COMMERCIAL	13,945,850	1,159,871,842	231,945	60,126	0.0832
24						
25	Industrial					
26	ALS	19,896	3,267,782			0.1642
27	LGS	7,908,583	439,311,200	251	31,508,299	0.0555
28	MGS	524,903	48,595,913	1,239	423,651	0.0926
29	SGS	1,934,702	129,008,728	2,588	747,566	0.0667
30	SI	2,536	285,305	20	126,800	0.1125
31	SLS	121	22,029	20	6,050	0.1821
32	GS	195	30,075	4	48,750	0.1542
33	Unbilled Revenue	26,189	1,465,610			0.0560
34	TOTAL INDUSTRIAL	10,417,125	621,986,642	4,122	2,527,202	0.0597
35						
36	Public Street Lighting					
37	SLS	74,795	19,006,945	592	126,343	0.2541
38	TSS	5,351	439,482	864	6,193	0.0821
39	Unbilled Revenue	-21	80,778			-3.8466
40	TOTAL PUBLIC STREET LIGHT	80,125	19,527,205	1,456	55,031	0.2437
41	TOTAL Billed	43,053,378	3,708,856,043	1,547,496	27,821	0.0861
42	Total Unbilled Rev.(See Instr. 6)	216,632	17,834,534	0	0	0.0823
43	TOTAL	43,270,010	3,726,690,577	1,547,496	27,961	0.0861

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	04/12/2018	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	Other Public Authority					
3	ALS	2	201			0.1005
4	MGS					
5	LGS	1,450,833	80,892,174	5	290,166,600	0.0558
6	Unbilled Revenue	4,010	199,010			0.0496
7	TOTAL OTHER PUBLIC AUTH	1,454,845	81,091,385	5	290,969,000	0.0557
8						
9						
10						
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41	TOTAL Billed	43,053,378	3,708,856,043	1,547,496	27,821	0.0861
42	Total Unbilled Rev.(See Instr. 6)	216,632	17,834,534	0	0	0.0823
43	TOTAL	43,270,010	3,726,690,577	1,547,496	27,961	0.0861

Schedule Page: 304 Line No.: 6 Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue excluded from this line is $17,795,794.

Schedule Page: 304 Line No.: 23 Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue excluded from this line is $24,207,330.

Schedule Page: 304 Line No.: 34 Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue excluded from this line is $1,863,782.

Schedule Page: 304 Line No.: 40 Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue excluded from this line is $110,309.

Schedule Page: 304.1 Line No.: 7 Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue excluded from this line is $3,991.

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Non-Requirement Sales					
2	Duke Energy Carolinas, LLC	LF	190			
3	Duke Energy Carolinas, LLC	AD	190			
4	PJM Interconnection L.L.C.	OS	7			
5	PJM Interconnection L.L.C.	AD	7			
6	South Carolina Electric & Gas	OS	97			
7	South Carolina Public Service Authority	OS	104	200		
8						
9	Requirement Sales					
10	Town of Black Creek, NC	RQ	174	3	3	3
11	Town of Black Creek, NC	RQ	174			
12	City of Camden, SC	RQ	197	37	38	37
13	City of Camden, SC	RQ	197			
14	PWC of the City of Fayetteville	RQ	184	365	370	365
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PWC of the City of Fayetteville	RQ	184			
2	French Broad EMC	RQ	195	78	86	78
3	French Broad EMC	RQ	195			
4	Haywood EMC	RQ	180	14	21	15
5	Haywood EMC	RQ	180	1		
6	Town of Lucama, NC	RQ	175	4	4	4
7	Town of Lucama, NC	RQ	175			
8	NC Electric Membership Corporation	OS	4			
9	NC Electric Membership Corporation	RQ	134	970	970	970
10	NC Electric Membership Corporation	RQ	134			
11	NC Electric Membership Corporation	RQ	182	701	722	701
12	NC Electric Membership Corporation	RQ	182			
13	NC Eastern Municipal Power Agency	RQ	200	1059	1243	1059
14	NC Eastern Municipal Power Agency	RQ	200			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Piedmont EMC	RQ	172	18	19	18
2	Piedmont EMC	RQ	172			
3	Town of Sharpsburg, NC	RQ	176	4	4	4
4	Town of Sharpsburg, NC	RQ	176			
5	Town of Stantonsburg, NC	RQ	177	4	4	4
6	Town of Stantonsburg, NC	RQ	177			
7	Town of Waynesville, NC	RQ	185			
8	Town of Winterville, NC	RQ	178	12	12	12
9	Town of Winterville, NC	RQ	178			
10						
11						
12	NC Electric Membership Corporation	OS	134			
13	NC Eastern Municipal Power Agency	OS	268			
14	Piedmont EMC	OS	322			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Town of Black Creek, NC	OS	293			
2	City of Camden, SC	OS	309			
3	PWC of the City of Fayetteville	OS	324			
4	French Broad EMC	OS	326			
5	Town of Lucama, NC	OS	294			
6	Town of Sharpsburg, NC	OS	296			
7	Town of Stantonsburg, NC	OS	295			
8	Town of Winterville, NC	OS	321			
9	Industrial Power Generating Corp.	OS	288			
10	Other					
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
5,313,446		145,535,212		145,535,212	2
1,792		56,457		56,457	3
52,204		3,744,821		3,744,821	4
1		9,120		9,120	5
1,593		57,649		57,649	6
400	64,000	52,020		116,020	7
					8
					9
12,809	529,668	385,379		915,047	10
		2,171		2,171	11
192,686	7,451,822	5,041,949		12,493,771	12
	-973,482	28,256		-945,226	13
2,079,777	75,308,206	55,550,105		130,858,311	14
18,060,645	616,814,255	479,209,237	0	1,096,023,492	
5,492,081	7,894,000	154,020,204	-6,238	161,907,966	
23,552,726	**624,708,255**	**633,229,441**	**-6,238**	**1,257,931,458**	

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	4,092,341	-250,016		3,842,325	1
526,258	15,996,294	14,160,720		30,157,014	2
-64		9,519		9,519	3
72,835	2,016,724	1,940,278		3,957,002	4
	180,295	-662		179,633	5
20,257	829,138	608,319		1,437,457	6
		3,350		3,350	7
122,487	7,830,000	4,564,485		12,394,485	8
6,737,982	136,048,488	178,667,337		314,715,825	9
-15,404		-918,662		-918,662	10
840,383	138,430,442	22,095,469		160,525,911	11
-86		-335,233		-335,233	12
7,432,066	218,375,788	198,503,731		416,879,519	13
	11,724,816	-950,377		10,774,439	14
18,060,645	616,814,255	479,209,237	0	1,096,023,492	
5,492,081	7,894,000	154,020,204	-6,238	161,907,966	
23,552,726	**624,708,255**	**633,229,441**	**-6,238**	**1,257,931,458**	

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
66,669	3,409,427	1,771,410		5,180,837	1
		12,756		12,756	2
18,876	742,679	569,200		1,311,879	3
		3,281		3,281	4
21,827	845,791	651,664		1,497,455	5
-283	-12,349	446		-11,903	6
		14,299		14,299	7
54,057	1,818,167	1,635,734		3,453,901	8
		8,814		8,814	9
					10
					11
76			-3,810	-3,810	12
			-1,696	-1,696	13
			-50	-50	14
18,060,645	616,814,255	479,209,237	0	1,096,023,492	
5,492,081	7,894,000	154,020,204	-6,238	161,907,966	
23,552,726	**624,708,255**	**633,229,441**	**-6,238**	**1,257,931,458**	

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	04/12/2018	End of 2017/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			-5	-5	1
			-59	-59	2
			-601	-601	3
			-136	-136	4
			-8	-8	5
			-7	-7	6
			-6	-6	7
			-20	-20	8
82			160	160	9
		440		440	10
					11
					12
					13
					14
18,060,645	616,814,255	479,209,237	0	1,096,023,492	
5,492,081	7,894,000	154,020,204	-6,238	161,907,966	
23,552,726	**624,708,255**	**633,229,441**	**-6,238**	**1,257,931,458**	

Schedule Page: 310 Line No.: 11 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310 Line No.: 13 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 1 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 3 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 5 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 7 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 10 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 12 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.1 Line No.: 14 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 2 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 4 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 6 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 7 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 9 Column: b

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 12 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.2 Line No.: 13 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.2 Line No.: 14 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 1 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 2 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 3 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 4 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 5 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 6 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 7 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 8 Column: j

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 9 Column: j

Other charge is for generation imbalance services

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	04/12/2018	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	7,040,867	8,823,917
5	(501) Fuel	338,758,341	410,031,826
6	(502) Steam Expenses	18,814,807	23,111,112
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	13,057	84,862
10	(506) Miscellaneous Steam Power Expenses	9,483,711	7,145,638
11	(507) Rents	27,797	
12	(509) Allowances	6,626,420	306,867
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	380,765,000	449,504,222
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,166,788	6,844,048
16	(511) Maintenance of Structures	9,053,239	9,413,704
17	(512) Maintenance of Boiler Plant	30,666,173	43,515,606
18	(513) Maintenance of Electric Plant	6,347,779	9,787,139
19	(514) Maintenance of Miscellaneous Steam Plant	7,851,475	6,152,852
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	59,085,454	75,713,349
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	439,850,454	525,217,571
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	41,036,569	44,785,075
25	(518) Fuel	205,734,454	199,311,766
26	(519) Coolants and Water	21,251,403	20,399,547
27	(520) Steam Expenses	45,888,808	50,372,305
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,917,431	6,133,709
31	(524) Miscellaneous Nuclear Power Expenses	164,876,067	170,974,243
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	484,704,732	491,976,645
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	75,518,912	72,169,715
36	(529) Maintenance of Structures	16,278,404	25,715,675
37	(530) Maintenance of Reactor Plant Equipment	63,874,892	67,425,121
38	(531) Maintenance of Electric Plant	41,119,415	48,809,983
39	(532) Maintenance of Miscellaneous Nuclear Plant	52,263,913	61,211,282
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	249,055,536	275,331,776
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	733,760,268	767,308,421
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,043,886	1,812,177
45	(536) Water for Power	62,500	62,500
46	(537) Hydraulic Expenses	-414,845	-223,725
47	(538) Electric Expenses	102,002	91,095
48	(539) Miscellaneous Hydraulic Power Generation Expenses	794,875	789,899
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,588,418	2,531,946
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	245,450	218,008
54	(542) Maintenance of Structures	256,607	331,428
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,333,948	1,439,806
56	(544) Maintenance of Electric Plant	707,046	456,821
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,831,372	2,234,903
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,374,423	4,680,966
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	6,962,841	7,212,912

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	04/12/2018	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,451,442	4,459,099
63	(547) Fuel	710,918,033	679,990,220
64	(548) Generation Expenses	3,139,556	3,098,072
65	(549) Miscellaneous Other Power Generation Expenses	14,091,328	13,150,559
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	731,600,359	700,697,950
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	6,820,301	4,283,381
70	(552) Maintenance of Structures	4,983,289	7,770,653
71	(553) Maintenance of Generating and Electric Plant	16,360,833	30,672,705
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	15,909,903	15,454,100
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	44,074,326	58,180,839
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	775,674,685	758,878,789
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	531,947,253	485,581,581
77	(556) System Control and Load Dispatching	1,577,306	1,629,675
78	(557) Other Expenses	-89,054,991	145,624,149
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	444,469,568	632,835,405
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,400,717,816	2,691,453,098
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	21,353	-4,530
84			
85	(561.1) Load Dispatch-Reliability	2,913,513	2,436,540
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,122,232	2,191,336
87	(561.3) Load Dispatch-Transmission Service and Scheduling	898,414	940,162
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	304,130	292,406
90	(561.6) Transmission Service Studies	124	-94,892
91	(561.7) Generation Interconnection Studies	204,069	-16,221
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,149,024	1,465,991
94	(563) Overhead Lines Expenses	910,085	844,247
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	304	761
97	(566) Miscellaneous Transmission Expenses	7,808,472	6,916,068
98	(567) Rents	3,082,952	95,951
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,414,672	15,067,819
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		3,502
102	(569) Maintenance of Structures	1,628,827	280,089
103	(569.1) Maintenance of Computer Hardware	3,908	27,684
104	(569.2) Maintenance of Computer Software	1,906,119	2,735,383
105	(569.3) Maintenance of Communication Equipment		10,142
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,058,579	5,599,790
108	(571) Maintenance of Overhead Lines	11,760,895	23,519,116
109	(572) Maintenance of Underground Lines		-1,192
110	(573) Maintenance of Miscellaneous Transmission Plant	36,342	-759,297
111	TOTAL Maintenance (Total of lines 101 thru 110)	19,394,670	31,415,217
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	38,809,342	46,483,036

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	466,256	717,977
135	(581) Load Dispatching	4,189,184	5,214,815
136	(582) Station Expenses	1,255,294	1,341,524
137	(583) Overhead Line Expenses	784,874	191,075
138	(584) Underground Line Expenses	4,512,350	4,712,175
139	(585) Street Lighting and Signal System Expenses	7,964	10,276
140	(586) Meter Expenses	8,320,395	7,511,340
141	(587) Customer Installations Expenses	3,301,211	2,013,972
142	(588) Miscellaneous Expenses	31,050,172	25,567,942
143	(589) Rents	4,120,922	2,533,934
144	TOTAL Operation (Enter Total of lines 134 thru 143)	58,008,622	49,815,030
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	12,553	8,189
147	(591) Maintenance of Structures	17,474	1,296
148	(592) Maintenance of Station Equipment	3,185,541	4,077,049
149	(593) Maintenance of Overhead Lines	77,989,270	96,344,656
150	(594) Maintenance of Underground Lines	4,550,204	4,822,769
151	(595) Maintenance of Line Transformers	751,963	798,661
152	(596) Maintenance of Street Lighting and Signal Systems	7,789,248	6,812,010
153	(597) Maintenance of Meters	1,638,226	1,801,325
154	(598) Maintenance of Miscellaneous Distribution Plant	-444,674	1,426,022
155	TOTAL Maintenance (Total of lines 146 thru 154)	95,489,805	116,091,977
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	153,498,427	165,907,007
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	207,031	281,077
160	(902) Meter Reading Expenses	5,399,741	4,468,044
161	(903) Customer Records and Collection Expenses	33,941,775	35,514,951
162	(904) Uncollectible Accounts	6,504,470	6,972,450
163	(905) Miscellaneous Customer Accounts Expenses	923,578	663,023
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	46,976,595	47,899,545

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	04/12/2018	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	217	5,832
169	(909) Informational and Instructional Expenses	52,532	81,137
170	(910) Miscellaneous Customer Service and Informational Expenses	4,029,991	4,393,350
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	4,082,740	4,480,319
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	522	
175	(912) Demonstrating and Selling Expenses	5,721,905	5,976,581
176	(913) Advertising Expenses	397,975	314,113
177	(916) Miscellaneous Sales Expenses	87,106	16,591
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	6,207,508	6,307,285
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	81,825,259	116,700,862
182	(921) Office Supplies and Expenses	52,335,065	43,547,509
183	(Less) (922) Administrative Expenses Transferred-Credit	-6,054	-78,844
184	(923) Outside Services Employed	58,130,801	46,129,197
185	(924) Property Insurance	7,696,580	18,253,708
186	(925) Injuries and Damages	10,215,504	16,348,146
187	(926) Employee Pensions and Benefits	90,966,041	87,327,116
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,127,626	7,495,556
190	(929) (Less) Duplicate Charges-Cr.	5,183,862	3,209,674
191	(930.1) General Advertising Expenses	3,368,011	2,196,396
192	(930.2) Miscellaneous General Expenses	-26,725,134	-29,538,333
193	(931) Rents	33,934,039	33,939,086
194	TOTAL Operation (Enter Total of lines 181 thru 193)	313,695,984	339,268,413
195	Maintenance		
196	(935) Maintenance of General Plant	757,109	1,397,538
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	314,453,093	340,665,951
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,964,745,521	3,303,196,241

Schedule Page: 320 Line No.: 5 Column: b

Accounts 501007, 501008, and 501009 for Beneficial Reuse in the amount of $32,534,556 are excluded from fuel totals allocated by plant on Form 1 pages 402 and 403.

Schedule Page: 320 Line No.: 5 Column: c

Amount reflects $3,294,460 of merger related fuel synergies not allocated by plant.

Schedule Page: 320 Line No.: 6 Column: c

Amount reflects ($148,685) of merger related reagent and by-product synergies not allocated to plant.

Schedule Page: 320 Line No.: 63 Column: c

Amount reflects ($5,863,197) of merger related gas capacity synergies not allocated by plant.

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	101 South Main LLC	LU	1			
2	1529 Properties, LLC	LU	1			
3	2315 Atlantic Ave Solar, LLC	LU	1			
4	ABCZ Solar LLC	LU	1			
5	Adnan Nasir	LU	1			
6	Adventure Solar	LU	1			
7	Alan Hardacre	LU	1			
8	Albert Adcock	LU	1			
9	Albertson Solar LLC	LU	1			
10	Alice Martin-Adkins	LU	1			
11	Alice Rosser	LU	1			
12	Allison Lee	LU	1			
13	Alvin Easton	LU	1			
14	AM Best Farm, LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Ambient Advisory Services	LU	1			
2	Amy Underwood	LU	1			
3	Anderson Solar LLC	LU	1			
4	Andrew Solar	LU	1			
5	Angier Farm LLC	LU	1			
6	Ann Matthew (Rano Thomas Matthew)	LU	1			
7	Arba Solar	LU	1			
8	Archer Daniels	LU	1			
9	Arden Solar	LU	1			
10	Argand Rooftop 1 LLC	LU	1			
11	Argand Rooftop 3 LLC	LU	1			
12	Argand Rooftop 3 LLC	LU	1			
13	Argand Rooftop 4 LLC	LU	1			
14	Argand SPP2 LLC	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arthur Zuco	LU	1			
2	Aspen Solar LLC	LU	1			
3	Atkinson Farm, LLC	LU	1			
4	Axiom Environmental INC	LU	1			
5	B & K Timber LLC	LU	1			
6	B.V. Hedrick Gravel & Sand Co	LU	1			
7	Balsam Solar, LLC	LU	1			
8	Baltimore Church	LU	1			
9	Barbara Howard	LU	1			
10	Barkley-Sexton Energy LLC	LU	1			
11	Barry Estes	LU	1			
12	Battye Solar LLC	LU	1			
13	Bayer Cropscience LP	LU	1			
14	Bearford Farm	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bearford Farm, LLC	LU	1			
2	Beaufort Solar	LU	1			
3	Ben Edson	LU	1			
4	Bertram Kalet	LU	1			
5	Beulaville Solar LLC	LU	1			
6	Beverly Lincoln	LU	1			
7	BGE Carolina Sunsense I LLC	LU	1			
8	Billy Moon	LU	1			
9	Biltmore Natural Resources INC	LU	1			
10	Biscoe Solar	LU	1			
11	Bizzell Church Solar	LU	1			
12	Bizzell Church Solar 2	LU	1			
13	Black Creek	LU	1			
14	Bladenboro Farm, LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Bladenboro Solar, LLC	LU	1			
2	Blueberry One	LU	1			
3	Boaz Farm	LU	1			
4	Bolton Farm, LLC	LU	1			
5	Boone Guyton	LU	1			
6	Brandon Laroque	LU	1			
7	BRE NC Solar 1 LLC	LU	1			
8	Brenda Currin	LU	1			
9	Broadway Solar	LU	1			
10	Brooks Energy	LU	1			
11	Bruce Ford	LU	1			
12	Bruce J Rakay	LU	1			
13	Bruce Rakay	LU	1			
14	Buncombe County Landfill	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bunn Level Farm, LLC	LU	1			
2	C II METHANE MANAGEMENT IV LLC	LU	1			
3	Camp Rockmont for Boys INC	LU	1			
4	Candace Solar	LU	1			
5	Carolina Solar Energy, NCSU	LU	1			
6	Carolina Solar Energy, PCSP1	LU	1			
7	Carolina Solar Energy-EMJ	LU	1			
8	Carolina Tractor & Equipment Co	LU	1			
9	Castalia Solar LLC	LU	1			
10	Catherine Willis	LU	1			
11	CB Bladen Solar	LU	1			
12	CBC Alternative Energy LLC (NEW)	LU	1			
13	CBC Alternative Energy LLC (OLD)	LU	1			
14	Cedar Solar LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Chadbourn Farm, LLC	LU	1			
2	Charlene Abbott	LU	1			
3	Charles Lewis	LU	1			
4	Chauncey Farm LLC	LU	1			
5	Chei Solar	LU	1			
6	Choco Solar LLC	LU	1			
7	Chocowinity Pet Resort	LU	1			
8	Chocowinity Solar	LU	1			
9	Chocowinity Vet Hospital PLLC	LU	1			
10	Christiansted Port Terminal Corp.	LU	1			
11	Cirrus Solar	LU	1			
12	City of Raleigh Parks Recreation Depat	LU	1			
13	Clara Reed	LU	1			
14	Claudette Wren	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Clay Emerick	LU	1			
2	Clipperton Holdings	LU	1			
3	Coats Solar, LLC	LU	1			
4	Cohen Farm Solar	LU	1			
5	Constance Burns	LU	1			
6	Corc Solar LLC	LU	1			
7	Cornwall Solar	LU	1			
8	Cotten Farm	LU	1			
9	Covey Run Apartments LLC	LU	1			
10	Cox Lake Hydro Electric	LU	1			
11	CPI Roxboro	LU	1			
12	CPI Southport	LU	1			
13	Craig Eury	LU	1			
14	Craven County Wood Energy, LP	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Creech Solar 2, LLC	LU	1			
2	Crestwood Solar	LU	1			
3	Crockett Farm	LU	1			
4	Currin Solar Farm	LU	1			
5	Custom Packaging Inc	LU	1			
6	Dan Gilbert	LU	1			
7	Daniel Neustedter	LU	1			
8	Danielle Carr	LU	1			
9	Darlington Solar, LLC	LU	1			
10	Darren Dasburg	LU	1			
11	David Box	LU	1			
12	David Greune	LU	1			
13	David Tobin	LU	1			
14	Daystar Solar	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Debra Bapat	LU	1			
2	Deep Branch Farm, LLC	LU	1			
3	Deep River Hydro	LU	1			
4	Delco Farm	LU	1			
5	Deltec Homes Inc	LU	1			
6	Dement Farm, LLC	LU	1			
7	Dessie Solar Center	LU	1			
8	Detlef Knappe	LU	1			
9	Diana Haran	LU	1			
10	Don Jackson	LU	1			
11	Double S Energy	LU	1			
12	Double S Energy Corp	LU	1			
13	Douglas Brablec	LU	1			
14	DRPFC I LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Dunn Solar	LU	1			
2	Duplin Solar I, LLC	LU	1			
3	Duplin Solar II LLC	LU	1			
4	Earl Ransom (Ann Willard)	LU	1			
5	East Wayne Solar LLC	LU	1			
6	Easters Holdings LLC	LU	1			
7	Eastover Farm LLC	LU	1			
8	ED's Gunsmithing & Sporting Inc	LU	1			
9	Edward Lipetzky	LU	1			
10	Elaine Manning	LU	1			
11	Elaine Sale	LU	1			
12	Elisabeth Corley	LU	1			
13	Elizabeth Corley	LU	1			
14	Elm Solar	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Enerdyne Properties LLC	LU	1			
2	EnergyXchange INC	LU	1			
3	Environmental Resources	LU	1			
4	Erwin Farm LLC	LU	1			
5	ESA Four Oaks	LU	1			
6	ESA NC Solar LLC	LU	1			
7	ESA Newton Grove 1 NC LLC	LU	1			
8	ESA Princeton NC	LU	1			
9	ESA RENEWABLES III LLC	LU	1			
10	Eugene Keil	LU	1			
11	Eva Anderson (James Anderson Barn)	LU	1			
12	Eva Anderson (James Anderson House)	LU	1			
13	Evergreen Landscaping Ser Inc	LU	1			
14	EWP LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Exhibit Court Solar LLC	LU	1			
2	Exum Farm Solar, LLC	LU	1			
3	F & D Huebner LLC	LU	1			
4	Faison Solar LLC	LU	1			
5	Farrington Farm LLC	LU	1			
6	Farrington Farm LLC	LU	1			
7	Farrington Farm LLC	LU	1			
8	Farrington Farm LLC	LU	1			
9	Ferguson Solar LLC	LU	1			
10	First Christian Church	LU	1			
11	First Citizens Bank & Trust Co 1.14MW	LU	1			
12	First Citizens Bank & Trust Co 566KW	LU	1			
13	First Congregational Church	LU	1			
14	Floyd Solar	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	FLS Owner 80 LLC	LU	1			
2	FLS Owner II LLC	LU	1			
3	FLS Solar 10 LLC	LU	1			
4	FLS Solar 100 LLC	LU	1			
5	FLS Solar 110 LLC	LU	1			
6	FLS Solar 170 LLC	LU	1			
7	FLS Solar 20 LLC - Chatham (FLS Owner	LU	1			
8	FLS Solar 20 LLC (Greensquare)	LU	1			
9	FLS Solar 20, LLC - HCC	LU	1			
10	FLS Solar 200, LLC	LU	1			
11	FLS Solar 230, LLC - Warren Place	LU	1			
12	FLS Solar 260 LLC	LU	1			
13	FLS YK Farm LLC	LU	1			
14	Foxfire Farm LLC	LU	1			
	Total					

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Franklin Solar 2, LLC	LU	1			
2	Franklin Solar LLC	LU	1			
3	Franklinton Solar	LU	1			
4	Fremont Farms, LLC	LU	1			
5	Fresh Air Energy - Carter	LU	1			
6	Fresh Air Energy - Langley	LU	1			
7	Fresh Air Energy - Pecan	LU	1			
8	Fresh Air Energy XXXI - Little River	LU	1			
9	Fresh Air Thornton (Fresh Air XVI LLC)	LU	1			
10	Fuquay Farms, LLC	LU	1			
11	Gainey Solar, LLC	LU	1			
12	Garrell Solar Farm	LU	1			
13	Gary Kruse	LU	1			
14	Gary Shaver	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Gary Spodnick	LU	1			
2	Gaylond Owens	LU	1			
3	Gene Rainey	LU	1			
4	George King	LU	1			
5	Gerry Cobley	LU	1			
6	Glen Raven Solar LLC	LU	1			
7	Gordon Koncal	LU	1			
8	Grace Evans	LU	1			
9	Grant Ingersoll	LU	1			
10	Grant Todd	LU	1			
11	Granville Solar LLC	LU	1			
12	Greenfield Power GTP One LLC	LU	1			
13	Greg Cumberford	LU	1			
14	Gregory Poole Equip Co	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Gwendolyn Anderson	LU	1			
2	Happy Solar	LU	1			
3	Harrell's Hill Solar	LU	1			
4	Harvest Beulaville	LU	1			
5	Haywood Farm Solar	LU	1			
6	HCE Johnston I, LLC	LU	1			
7	Hector Farm, LLC	LU	1			
8	Hessler 115KW	LU	1			
9	Hessler 153KW	LU	1			
10	Hew Fulton Farm LLC	LU	1			
11	Hickory Nut Gap Farm, LLC	LU	1			
12	Highland Community Solar LLC	LU	1			
13	Highland Craftsmen INC	LU	1			
14	Highland Solar Center	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Highwater Solar	LU	1			
2	Holstein Holdings	LU	1			
3	Hood Farm Solar	LU	1			
4	Howard Larsen	LU	1			
5	Howard Plemmons	LU	1			
6	Hydrodyne-High Falls	LU	1			
7	Hydrodyne-Little River	LU	1			
8	Ideal Fastner Corp	LU	1			
9	Ingenco Renewables	LU	1			
10	Ingenco Wholesale	LU	1			
11	Innovative Solar 10	LU	1			
12	Innovative Solar 31, LLC	LU	1			
13	Innovative Solar 35, LLC	LU	1			
14	Innovative Solar 37, LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Innovative Solar 42	LU	1			
2	Innovative Solar 43, LLC	LU	1			
3	Innovative Solar 44 LLC	LU	1			
4	Innovative Solar 46, LLC	LU	1			
5	Innovative Solar 47 LLC	LU	1			
6	Innovative Solar 48 LLC	LU	1			
7	Innovative Solar 59, LLC	LU	1			
8	Innovative Solar 6	LU	1			
9	Innovative Solar 60, LLC	LU	1			
10	Innovative Solar 63	LU	1			
11	Innovative Solar 64 LLC	LU	1			
12	Innovative Solar 65, LLC	LU	1			
13	Innovative Solar6 P1	LU	1			
14	Innovative Solar6 P2	LU	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	International Paper	LU	1			
2	J Godwin (John)	LU	1			
3	J Hilton (Jeri)	LU	1			
4	Jack Bennett	LU	1			
5	Jackson & Sons, Inc	LU	1			
6	James Hubbell	LU	1			
7	James O Richard	LU	1			
8	James Thorpe	LU	1			
9	James Young (Asheville Alternative	LU	1			
10	James Young (Asheville Alt Energy)	LU	1			
11	Jane Garvey	LU	1			
12	Janet Dektor	LU	1			
13	Jason Hibbets	LU	1			
14	Jason Sprouse	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Jay Dechesere	LU	1			
2	Jay Lindenmuth	LU	1			
3	Jean Cassidy	LU	1			
4	Jennifer Cole	LU	1			
5	Jennifer Macri	LU	1			
6	Jerry Braxton	LU	1			
7	Jerry Sullivan	LU	1			
8	Jessica Larsen (Chris Larsen)	LU	1			
9	Jim Sherrer	LU	1			
10	JoAnn Goddard	LU	1			
11	John Donoghue	LU	1			
12	John Hollingsworth	LU	1			
13	John McDermott	LU	1			
14	John Reese	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	John Sorge	LU	1			
2	Johnson Breeders	LU	1			
3	Jordan Hydroelectric LLC	LU	1			
4	Joseph Callahan	LU	1			
5	Joseph Ponzi	LU	1			
6	JT Hobby & Sons, Inc.	LU	1			
7	Judith Webb	LU	1			
8	K & HB Enterprises LLC - Waynesville	LU	1			
9	K & HB Enterprises LLC - Asheville	LU	1			
10	Karen Jordan	LU	1			
11	Karen Mallam	LU	1			
12	Karl Werner	LU	1			
13	Kathy Hansinger	LU	1			
14	Kathy Triplett	LU	1			
	Total					

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Keen Farm	LU	1			
2	Kelly Daiker	LU	1			
3	Kenansville Solar 2 LLC	LU	1			
4	Kenansville Solar Farm LLC (Heelstone	LU	1			
5	Kenansville Solar LLC (FLS Energy)	LU	1			
6	Kennedy Solar	LU	1			
7	Kenneth Rich	LU	1			
8	Kenneth Solar	LU	1			
9	Kinston Davis Farm	LU	1			
10	Kinston Solar LLC	LU	1			
11	Kirkwall Holdings LLC	LU	1			
12	Kojak farm	LU	1			
13	Kris Coeytaux	LU	1			
14	Kristen Blackley	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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1	Kristin Petersen	LU	1			
2	L&D Incorporated	LU	1			
3	L&S Waterpower	LU	1			
4	Lake Upchurch Power Inc.	LU	1			
5	Land of the Sky MT (Eden Solar/Innova)	LU	1			
6	Laney Development Inc	LU	1			
7	Lang Solar	LU	1			
8	Langdon Solar	LU	1			
9	Lanier Solar	LU	1			
10	Laurinburg Solar LLC	LU	1			
11	Lea Romano	LU	1			
12	Lenior Farm 1, LLC	LU	1			
13	Lenior Farm 2, LLC	LU	1			
14	Leon Petty	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Leonard Bernstein	LU	1			
2	Lewis Rothlein	LU	1			
3	Lillington Solar	LU	1			
4	Linda Sweeney	LU	1			
5	Lisa Mangini	LU	1			
6	Lloyd Fitzwater	LU	1			
7	Logan Trading Co, Inc.	LU	1			
8	Lumberton Power	LU	1			
9	M B Haynes Corporation 12KW	LU	1			
10	M B Haynes Corporation 24KW	LU	1			
11	M Stone (Mike)	LU	1			
12	Madison Hydro Partners	LU	1			
13	Mahadev Enterprises LLC	LU	1			
14	Manway Farm LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Marc Parham	LU	1			
2	Margaret Hayes	LU	1			
3	Mark Blessington	LU	1			
4	Mark Parker	LU	1			
5	Marshall's Locksmith Services Inc	LU	1			
6	Martin Creek Farm LLC	LU	1			
7	Matthew Jansohn	LU	1			
8	Maxton Solar 1	LU	1			
9	McCallum Farm	LU	1			
10	McGoogan Farm	LU	1			
11	McKenzie Farm LLC	LU	1			
12	MDK Cornerstone, LLC	LU	1			
13	Melinda Solar LLC	LU	1			
14	Meriwether Farm	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Metropolitan Sewerage	LU	1			
2	Michael Nicklas	LU	1			
3	Michael Rowland	LU	1			
4	Michael Thorn	LU	1			
5	Michael Walters	LU	1			
6	Mildred Long	LU	1			
7	Mile Farm LLC	LU	1			
8	Mill Pond Solar Farm	LU	1			
9	Mill Pond Solar Farm Test (September)	LU	1			
10	Mills Anson Farm	LU	1			
11	Miriam Clayton	LU	1			
12	Moncure Farm LLC	LU	1			
13	Montgomery Solar	LU	1			
14	Moorings Farm 2, LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Moorings Farm, LLC	LU	1			
2	Morgan Farm	LU	1			
3	Morton Barlaz	LU	1			
4	Mount Olive Solar	LU	1			
5	MP Wayne County Landfill	LU	1			
6	Mt Olive Farm	LU	1			
7	Mt Olive Farm 2 LLC	LU	1			
8	Mt Olive Solar 1 LLC	LU	1			
9	Munich Motors INC	LU	1			
10	Murdock Solar	LU	1			
11	Nancy Pope	LU	1			
12	Nash 58 Farm	LU	1			
13	Nash 64 Farm	LU	1			
14	Nash 97 Solar	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Nashville Farms LLC	LU	1			
2	Nathan Conroy	LU	1			
3	NC State Museum of Nat Science	LU	1			
4	NCEMC - Ajax	LU	1			
5	NCEMC - Bear Creek Solar	LU	1			
6	NCEMC - Flint Solar	LU	1			
7	NCEMC - Jersey Holdings Solar	LU	1			
8	NCEMC - Long Henry Solar	LU	1			
9	NCEMC - Revolution Dial Road	LU	1			
10	NCEMC - Revolution Ezzel Road	LU	1			
11	NCEMC - Robeson Landfill	LU	1			
12	NCEMC - Robeson Landfill (Phase 1)	LU	1			
13	NCEMC - Robeson Landfill (Phase 2)	LU	1			
14	NCEMC - Rosewood Solar	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	NCEMC - Ruskin Solar	LU	1			
2	NCEMC - Scarlett Solar	LU	1			
3	NCEMC - Snow Camp Solar	LU	1			
4	NCEMC - Storm Hog Partners	LU	1			
5	NCEMC - Storm Hog Partners 2	LU	1			
6	NCEMC - Sunny Point	LU	1			
7	NCEMC - Viper Solar	LU	1			
8	NCEMC-Ajax	LU	1			
9	NCEMPA	LU	1			
10	Neil Caudle	LU	1			
11	Neuse River Solar Farm LLC	LU	1			
12	New Bern Farm LLC	LU	1			
13	Nitro Solar LLC	LU	1			
14	North Carolina Solar I LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	North Carolina Solar II LLC	LU	1			
2	North Carolina Solar III Lessee LLC	LU	1			
3	North Nash Farm LLC	LU	1			
4	Northern States Power	LU	1			
5	Oakboro Farm LLC	LU	1			
6	Old Webbs Mill Hydro LLC	LU	1			
7	Old Wire Farm, LLC	LU	1			
8	Onslow Power Producers, LLC	LU	1			
9	P K Ventures Inc	LU	1			
10	Pate Farm LLC	LU	1			
11	Paul Konove	LU	1			
12	Paul Williamson	LU	1			
13	PCIP Solar Lessee LLC	LU	1			
14	PCSP3 Airport LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Perkins Solar	LU	1			
2	Peter Brezny	LU	1			
3	Pikeville Farm, LLC	LU	1			
4	Pinedale Springs	LU	1			
5	Pohoja Corporation (Kenneth Sheffield)	LU	1			
6	Pollocksville Solar, LLC	LU	1			
7	Porter Solar LLC	LU	1			
8	Prestage Agenergy NC	LU	1			
9	Prestage Farms, Inc.	LU	1			
10	Progress Solar I LLC	LU	1			
11	Progress Solar II, LLC	LU	1			
12	Progress Solar III, LLC	LU	1			
13	Quarters LLC	LU	1			
14	Quincy Solar, LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Raeford Farm	LU	1			
2	Railroad Farm	LU	1			
3	Railroad Farm 2, LLC	LU	1			
4	Railroad Solar Farm, LLC	LU	1			
5	Randy Secrist	LU	1			
6	Ravi Iyengar	LU	1			
7	Rebecca Graham	LU	1			
8	Red Hill Solar	LU	1			
9	Red Oak Solar Farm, LLC	LU	1			
10	Red Toad A Powatan Road LLC	LU	1			
11	Red Toad II LLC	LU	1			
12	REI 2 LLC	LU	1			
13	Renewable Power LLC (Foodlion)	LU	1			
14	RES AG DM 2-1 LLC (RES Agriculture NC)	LU	1			
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	RES AG DM 4-3 LLC (RES Agriculture NC)	LU	1			
2	Richard Muse	LU	1			
3	Riding Partners Bio	LU	1			
4	Riding Partners Biowheels	LU	1			
5	Riding Partners INC	LU	1			
6	Riding Partners INC #2	LU	1			
7	Riding Partners INC #3	LU	1			
8	Robert & Phyllis Wooten	LU	1			
9	Robert Beatty	LU	1			
10	Robert Depew	LU	1			
11	Robert Dick	LU	1			
12	Robert Ginsberg	LU	1			
13	Robert Harris	LU	1			
14	Robert Hicks	LU	1			
	Total					

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1	Robert Wooten	LU	1			
2	Rock Farm LLC	LU	1			
3	Rockingham Solar LLC	LU	1			
4	Rocky Mount Mills	LU	1			
5	Rocky River Hydro LLC	LU	1			
6	Roger Gendron	LU	1			
7	Ron Hess	LU	1			
8	Rose Hill Solar LLC	LU	1			
9	Roxboro Farm LLC	LU	1			
10	Roxboro Solar Farm	LU	1			
11	Roy Turnbaugh	LU	1			
12	Royal Solar LLC	LU	1			
13	Sam Rogers	LU	1			
14	Samarcand Solar Farm	LU	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Sampson Solar LLC	LU	1			
2	Sandy Cross Solar LLC	LU	1			
3	Sarah Cox	LU	1			
4	Sarah Solar LLC	LU	1			
5	SAS - 1200KW	LU	1			
6	SAS Institute - Building G	LU	1			
7	SAS Institute - Building T	LU	1			
8	SAS Institute Inc	LU	1			
9	Scott Shackleton	LU	1			
10	Sedberry Farm, LLC	LU	1			
11	SEGY LLC	LU	1			
12	Selma Solar Farm	LU	1			
13	Shaler Stidman	LU	1			
14	Shannon Farm	LU	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Siler 421 Farm, LLC	LU	1			
2	SMB Holding 10 LLC	LU	1			
3	SMB Holdings 5 LLC	LU	1			
4	Snow Hill Solar 2	LU	1			
5	Sol Sencia Ventures LLC (Paul Kazmer)	LU	1			
6	Solar 55 LLC	LU	1			
7	Solarworks RCC LLC	LU	1			
8	Soluga Farm I, LLC	LU	1			
9	Soluga Farm II LLC	LU	1			
10	Soluga Farm III LLC	LU	1			
11	Sonne One LLC	LU	1			
12	Soul City Solar	LU	1			
13	South Atlantic Services	LU	1			
14	South Louisburg Solar	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	South Robeson Solar Farm, LLC	LU	1			
2	Southeastern Freight Lines	LU	1			
3	Southerland Farms	LU	1			
4	Spicewood Solar Farm	LU	1			
5	Spring Valley Solar 2	LU	1			
6	St. Pauls Solar 1, LLC	LU	1			
7	St. Pauls Solar 2, LLC	LU	1			
8	Stagecoach Solar LLC	LU	1			
9	Stainback Solar Farm	LU	1			
10	Steve Zarnowski (FLAT CREEK)	LU	1			
11	Steven Forbes	LU	1			
12	Stone Solar Farm, LLC	LU	1			
13	Strata Fund 11 Lessee, LLC	LU	1			
14	Stress Real Estate Holdings LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Stuart Higgins	LU	1			
2	Sumter Heat & Power LLC	LU	1			
3	Sun Devil Solar	LU	1			
4	Sundance Power Systems INC	LU	1			
5	SunE Bearpond Lessee	LU	1			
6	SunE Graham Lessee	LU	1			
7	SunE NC Progress, LLC	LU	1			
8	SunE Shankle Lessee	LU	1			
9	Sunenergy1-Asheville LLC	LU	1			
10	Sunfish Solar	LU	1			
11	Sunstruck Energy LLC	LU	1			
12	Susan Broadhead	LU	1			
13	Susan Jones (James A Jones)	LU	1			
14	Sweetgum Solar	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tart Farm	LU	1			
2	Terri Lechner	LU	1			
3	Thaddeus Burgess Trust	LU	1			
4	The Big Chicken LLC	LU	1			
5	The N C Growers Assoc Inc	LU	1			
6	The Rock Solar Energy Plant LLC	LU	1			
7	Theresa Galvin (Bruce Rakay or John G)	LU	1			
8	Thomas Reese	LU	1			
9	Thorsten Degenhardt	LU	1			
10	Timothy Forrest	LU	1			
11	Tony Gaddis	LU	1			
12	Town of Warsaw Solar	LU	1			
13	Town Square West	LU	1			
14	Tracy Davids	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tracy Solar	LU	1			
2	Tria Cline	LU	1			
3	Tryon Road INC	LU	1			
4	Turkey Branch Solar (FLS 2014 SOLAR A)	LU	1			
5	TWE Chocowinity	LU	1			
6	TWE Kinston Solar	LU	1			
7	TWE Laurinburg	LU	1			
8	TWE New Bern Solar	LU	1			
9	US Dept of Commerce NOAA (Randy Grady)	LU	1			
10	Uwharrie Mountain Renewables	LU	1			
11	Vance Solar 1	LU	1			
12	Vandy LLC	LU	1			
13	Vickers Solar Farm	LU	1			
14	Vicksburg Solar LLC	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	W.E. Partners IV LLC	LU	1			
2	Wadesboro Farm	LU	1			
3	Wadesboro Farm 2	LU	1			
4	Wadesboro Farm 3	LU	1			
5	Wagstaff Farm 1, LLC	LU	1			
6	Wake Tech Innovations Inc	LU	1			
7	Wallace Solar	LU	1			
8	Warren Reed	LU	1			
9	Warren Wilson College	LU	1			
10	Warrenton Farm, LLC	LU	1			
11	Warsaw Solar	LU	1			
12	Warsaw Solar 2 LLC	LU	1			
13	Watts Farm	LU	1			
14	Wayne County Public Schools	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Wayne Hilbert	LU	1			
2	Wayne Solar I, LLC	LU	1			
3	Wayne Solar II, LLC	LU	1			
4	Wayne Solar III, LLC	LU	1			
5	Wellons Farm	LU	1			
6	West Siler Farm, LLC	LU	1			
7	Westgate Auto Group LLC	LU	1			
8	Weyerhaesuer NR	LU	1			
9	William Harlan	LU	1			
10	William Hewitt	LU	1			
11	William Kelly	LU	1			
12	William Werdel	LU	1			
13	Wilson Farm 1, LLC	LU	1			
14	Woodland Church Farm	LU	1			
	Total					

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	04/12/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Wortham Solar	LU	1			
2	Yanceyville Farm 2 LLC	LU	1			
3	Yanceyville Farm 3 LLC	LU	1			
4	Yanceyville Farm LLC	LU	1			
5	ZV Solar 1	LU	1			
6	ZV Solar 2	LU	1			
7	ZV Solar 3	LU	1			
8	Broad River Energy, LLC	LU	1			
9	Broad River Energy, LLC	AD	1			
10	City of Fayetteville (Butler Warner)	LU				
11	City of Fayetteville (Butler Warner)	AD				
12	Southern Company Services	LU	7			
13	PJM Settlements, Inc.	OS	188			
14	PJM Settlements, Inc.	AD	188			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Haywood Electric Membership Corp	LF	180			
2	Haywood Electric Membership Corp	AD	180			
3	North Carolina Electric Membership	LF	182			
4	North Carolina Electric Membership	AD	182			
5	Duke Energy Carolinas, LLC	OS	190			
6	Duke Energy Carolinas, LLC	AD	190			
7	Duke Energy Carolinas, LLC	OS	45			
8	Duke Energy Carolinas, LLC	OS	4			
9	Cargill Power Markets	SF	193			
10	Rock TennCP, LLC	EX	4			
11	North Carolina Electric Member Corp	EX	4			
12	Industrial Power Generation Corp	EX	4			
13	Town of Waynesville	EX	4			
14	Net Metering					
	Total					

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Miscellaneous					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-1				-61		-61	1
55				3,338		3,338	2
615				47,121		47,121	3
631				39,489		39,489	4
2				102		102	5
154				12,765		12,765	6
1				41		41	7
42				3,210		3,210	8
11,595				771,159		771,159	9
-2				-76		-76	10
10				686		686	11
5				240		240	12
15				1,162		1,162	13
8,503				707,681		707,681	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11				541		541	1
4				218		218	2
3,850				319,154		319,154	3
9,762				653,588		653,588	4
8,114				669,800		669,800	5
8				532		532	6
2,969				243,236		243,236	7
24				859		859	8
276				13,700		13,700	9
702				53,721		53,721	10
27				2,028		2,028	11
234				17,945		17,945	12
710				54,349		54,349	13
353				22,067		22,067	14
7,773,905			106,951,172	424,996,081		531,947,253	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-2				-111		-111	1
9,785				655,995		655,995	2
9,683				647,271		647,271	3
8				586		586	4
16				1,238		1,238	5
16				1,204		1,204	6
9,662				646,859		646,859	7
1,197				63,876		63,876	8
				-10		-10	9
86				5,198		5,198	10
13				651		651	11
33				2,061		2,061	12
31				1,959		1,959	13
1,717				112,032		112,032	14
7,773,905			106,951,172	424,996,081		531,947,253	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7,929				529,714		529,714	1
26,829				1,787,716		1,787,716	2
3				175		175	3
12				1,009		1,009	4
3,517				289,235		289,235	5
				-13		-13	6
600				45,912		45,912	7
10				499		499	8
2,238				110,288		110,288	9
9,026				530,278		530,278	10
10,000				672,114		672,114	11
3,137				210,937		210,937	12
66,527				4,027,534		4,027,534	13
8,884				731,915		731,915	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,187				680,906		680,906	1
9,883				662,351		662,351	2
3,422				230,230		230,230	3
9,305				768,750		768,750	4
4				225		225	5
17				1,289		1,289	6
9,203				615,588		615,588	7
3				142		142	8
9,702				800,249		800,249	9
893				70,617		70,617	10
9				453		453	11
5				271		271	12
10				497		497	13
9,911				667,448		667,448	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,436				853,058		853,058	1
12,287				895,216		895,216	2
16				806		806	3
9,164				614,314		614,314	4
67				4,786		4,786	5
893				55,896		55,896	6
353				22,105		22,105	7
316				19,771		19,771	8
3,805				313,711		313,711	9
16				833		833	10
10,105				677,912		677,912	11
3,886				317,750		317,750	12
1,723				131,915		131,915	13
9,782				657,231		657,231	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,554				787,981		787,981	1
6				284		284	2
4				191		191	3
9,202				598,782		598,782	4
9,464				632,856		632,856	5
11,596				772,934		772,934	6
8				402		402	7
8,844				592,976		592,976	8
2				124		124	9
551				33,443		33,443	10
9,074				606,902		606,902	11
38				2,356		2,356	12
12				611		611	13
				17		17	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9				481		481	1
489				32,904		32,904	2
10,028				669,693		669,693	3
10,176				678,682		678,682	4
-1				-30		-30	5
352				29,305		29,305	6
10,331				846,817		846,817	7
11,198				690,901		690,901	8
10				487		487	9
515				42,788		42,788	10
333,416				25,476,155		25,476,155	11
427,359				33,586,872		33,586,872	12
9				632		632	13
370,046				21,803,074		21,803,074	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,591				636,008		636,008	1
9,280				621,609		621,609	2
8,898				578,816		578,816	3
9,375				587,786		587,786	4
253				19,372		19,372	5
4				217		217	6
							7
-1				-26		-26	8
21,158				1,141,616		1,141,616	9
4				170		170	10
							11
-1				-24		-24	12
5				272		272	13
2,101				121,798		121,798	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5				259		259	1
9,938				622,076		622,076	2
724				59,394		59,394	3
9,393				626,398		626,398	4
68				3,387		3,387	5
9,210				760,400		760,400	6
9,004				745,115		745,115	7
-1				-36		-36	8
3				149		149	9
4				199		199	10
13				958		958	11
3				169		169	12
-1				-4		-4	13
24				1,525		1,525	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
3,614				298,549		298,549	1
9,065				748,957		748,957	2
9,449				779,581		779,581	3
4				193		193	4
3,758				310,687		310,687	5
12				781		781	6
9,800				806,952		806,952	7
30				1,732		1,732	8
1				38		38	9
				-14		-14	10
-2				-85		-85	11
							12
1				55		55	13
9,933				666,599		666,599	14
7,773,905			106,951,172	424,996,081		531,947,253	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-36				-1,238		-1,238	1
12				605		605	2
4				195		195	3
7,690				501,661		501,661	4
9,256				600,950		600,950	5
614				47,001		47,001	6
3,590				295,611		295,611	7
9,063				589,857		589,857	8
1,570				98,298		98,298	9
							10
14				770		770	11
8				501		501	12
-1				-4		-4	13
576				37,007		37,007	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
527				43,763		43,763	1
9,313				623,531		623,531	2
33				2,078		2,078	3
3,343				218,539		218,539	4
72				5,495		5,495	5
1,494				114,414		114,414	6
							7
-25				-1,948		-1,948	8
189				9,347		9,347	9
24				1,391		1,391	10
1,266				62,643		62,643	11
504				24,417		24,417	12
							13
10,157				678,823		678,823	14
7,773,905			106,951,172	424,996,081		531,947,253	

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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,457				187,863		187,863	1
106				8,899		8,899	2
747				46,780		46,780	3
7,261				599,141		599,141	4
3,347				274,775		274,775	5
3,410				228,873		228,873	6
125				9,608		9,608	7
343				26,286		26,286	8
							9
6,844				457,958		457,958	10
9,113				609,990		609,990	11
9,811				657,902		657,902	12
69				4,351		4,351	13
10,093				675,926		675,926	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,319				276,074		276,074	1
3,261				268,505		268,505	2
6,038				402,930		402,930	3
587				34,262		34,262	4
10,012				670,224		670,224	5
10,059				674,154		674,154	6
10,188				680,981		680,981	7
9,369				629,758		629,758	8
9,005				605,611		605,611	9
8,293				683,786		683,786	10
3,803				253,325		253,325	11
7,469				615,512		615,512	12
7				368		368	13
20				1,021		1,021	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1				74		74	1
17				856		856	2
4				183		183	3
				-4		-4	4
							5
530				33,196		33,196	6
11				735		735	7
				-19		-19	8
				-9		-9	9
				16		16	10
4,516				345,851		345,851	11
306				19,196		19,196	12
-1				-35		-35	13
242				15,164		15,164	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				-17		-17	1
7,736				516,904		516,904	2
9,629				795,344		795,344	3
2,796				188,851		188,851	4
3,903				262,280		262,280	5
3,761				250,886		250,886	6
10,449				653,455		653,455	7
137				8,562		8,562	8
189				14,456		14,456	9
9,908				660,051		660,051	10
-1				-35		-35	11
53				2,979		2,979	12
10				503		503	13
10,209				686,373		686,373	14
7,773,905			106,951,172	424,996,081		531,947,253	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,493				635,751		635,751	1
39,642				2,113,230		2,113,230	2
3,827				260,721		260,721	3
6				296		296	4
16				811		811	5
327				25,822		25,822	6
85				7,216		7,216	7
270				20,666		20,666	8
42,030				2,864,742		2,864,742	9
22,430				967,619		967,619	10
2,553				169,905		169,905	11
65,256				4,191,525		4,191,525	12
3,322				208,502		208,502	13
98,793				6,064,563		6,064,563	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
45,231				2,178,466		2,178,466	1
75,297				4,491,864		4,491,864	2
9,351				626,175		626,175	3
165,193				8,813,986		8,813,986	4
56,298				3,392,687		3,392,687	5
9,606				642,570		642,570	6
3,563				223,972		223,972	7
573				36,593		36,593	8
3,637				227,157		227,157	9
9,101				609,815		609,815	10
9,056				605,421		605,421	11
8,977				559,173		559,173	12
581				37,766		37,766	13
1,304				84,076		84,076	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
966				34,453		34,453	1
18				904		904	2
6				319		319	3
1				76		76	4
30				1,871		1,871	5
4				216		216	6
-1				-66		-66	7
4				330		330	8
44				2,172		2,172	9
59				2,852		2,852	10
-1				-23		-23	11
7				364		364	12
9				430		430	13
2				85		85	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				19		19	1
1				98		98	2
-1				-45		-45	3
4				192		192	4
1				54		54	5
5				231		231	6
10				722		722	7
9				468		468	8
1				29		29	9
-1				-18		-18	10
1				-41		-41	11
8				562		562	12
12				583		583	13
6				209		209	14
7,773,905			106,951,172	424,996,081		531,947,253	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4				220		220	1
137				4,946		4,946	2
9,809				651,400		651,400	3
-1				-36		-36	4
11				560		560	5
1,188				100,634		100,634	6
5				284		284	7
33				2,042		2,042	8
30				1,848		1,848	9
-1				-46		-46	10
19				964		964	11
8				412		412	12
4				184		184	13
4				211		211	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,537				638,212		638,212	1
5				235		235	2
3,663				245,492		245,492	3
7,705				636,478		636,478	4
3,496				288,895		288,895	5
4,947				338,980		338,980	6
-1				-33		-33	7
5,236				352,174		352,174	8
9,363				610,984		610,984	9
3,748				310,133		310,133	10
9,742				652,108		652,108	11
9,484				635,713		635,713	12
3				195		195	13
6				299		299	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8				427		427	1
13				803		803	2
972				79,592		79,592	3
							4
92,592				5,472,672		5,472,672	5
13				984		984	6
9,868				660,652		660,652	7
9,532				637,347		637,347	8
9,972				666,602		666,602	9
4,523				301,009		301,009	10
6				283		283	11
8,582				708,845		708,845	12
9,159				753,762		753,762	13
-1				-43		-43	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3				169		169	1
4				352		352	2
1,716				93,114		93,114	3
5				332		332	4
-1				-31		-31	5
2				125		125	6
91				5,656		5,656	7
160,330				12,254,091		12,254,091	8
12				941		941	9
33				2,546		2,546	10
5				237		237	11
2,546				164,550		164,550	12
14				1,036		1,036	13
10,284				687,842		687,842	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6				289		289	1
8				418		418	2
1				30		30	3
7				373		373	4
17				1,295		1,295	5
5,594				461,519		461,519	6
-1				-29		-29	7
10,338				692,109		692,109	8
9,507				782,501		782,501	9
10,287				687,893		687,893	10
10,488				679,194		679,194	11
11				589		589	12
8,875				593,411		593,411	13
9,325				579,328		579,328	14
7,773,905			106,951,172	424,996,081		531,947,253	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8				371		371	1
-1				-33		-33	2
1				89		89	3
-1				-40		-40	4
2				102		102	5
4				226		226	6
9,021				745,721		745,721	7
1,943				106,735		106,735	8
9				450		450	9
9,639				643,686		643,686	10
-1				-34		-34	11
6,214				512,212		512,212	12
40,450				2,761,963		2,761,963	13
2,511				152,381		152,381	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,075				665,971		665,971	1
9,777				656,545		656,545	2
							3
3,915				261,050		261,050	4
11,943				726,228		726,228	5
10,004				825,588		825,588	6
9,279				766,089		766,089	7
8,643				577,889		577,889	8
4				187		187	9
7,576				504,300		504,300	10
2				169		169	11
9,211				762,179		762,179	12
7,729				638,904		638,904	13
9,776				655,728		655,728	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,780				310,988		310,988	1
5				237		237	2
9				467		467	3
914				48,138		48,138	4
576				30,500		30,500	5
9,683				487,784		487,784	6
111				5,140		5,140	7
1,170				65,061		65,061	8
1,541				105,594		105,594	9
2,301				160,329		160,329	10
1				35		35	11
3,294				227,386		227,386	12
1,542				82,952		82,952	13
553				30,133		30,133	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
608				32,458		32,458	1
1,232				68,494		68,494	2
11,617				636,121		636,121	3
3,791				254,407		254,407	4
461				21,708		21,708	5
1,962				111,524		111,524	6
592				31,545		31,545	7
487				30,387		30,387	8
239,991				15,782,904		15,782,904	9
-1				-60		-60	10
1,571				98,348		98,348	11
9,117				750,629		750,629	12
9,015				605,221		605,221	13
2,660				203,707		203,707	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,602				296,379		296,379	1
9,434				777,548		777,548	2
10,013				671,607		671,607	3
							4
9,730				632,917		632,917	5
				-19		-19	6
11,657				723,182		723,182	7
10,857				783,676		783,676	8
							9
9,672				796,838		796,838	10
				-9		-9	11
-1				-76		-76	12
1,797				112,486		112,486	13
3,876				296,785		296,785	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,927				246,814		246,814	1
4				203		203	2
444				25,169		25,169	3
101				6,296		6,296	4
35				1,716		1,716	5
10,301				686,816		686,816	6
8,528				530,791		530,791	7
128				7,183		7,183	8
252				20,068		20,068	9
5,599				468,182		468,182	10
6,351				523,554		523,554	11
6,254				512,875		512,875	12
545				41,706		41,706	13
5,379				363,819		363,819	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
9,429				774,952		774,952	1
9,036				742,279		742,279	2
10,363				856,166		856,166	3
8,043				538,119		538,119	4
				-5		-5	5
				-31		-31	6
							7
9,046				748,429		748,429	8
9,686				597,870		597,870	9
4,112				268,113		268,113	10
703				53,821		53,821	11
							12
225				14,071		14,071	13
							14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
							1
-10				-38		-38	2
14				831		831	3
				-14		-14	4
10				497		497	5
9				453		453	6
1				71		71	7
5				252		252	8
22				1,088		1,088	9
							10
6				327		327	11
							12
3				137		137	13
3				138		138	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8				340		340	1
9,578				788,777		788,777	2
10,145				676,734		676,734	3
							4
1				46		46	5
-1				-32		-32	6
9				615		615	7
3,499				288,156		288,156	8
9,167				755,828		755,828	9
9,287				577,608		577,608	10
5				261		261	11
8,969				601,839		601,839	12
10				511		511	13
9,292				766,807		766,807	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,118				276,381		276,381	1
2,045				156,570		156,570	2
-1				-48		-48	3
8,485				569,722		569,722	4
1,619				76,191		76,191	5
							6
							7
1,416				85,736		85,736	8
11				529		529	9
9,894				658,378		658,378	10
9				424		424	11
9,429				778,150		778,150	12
1				55		55	13
9,483				781,486		781,486	14
7,773,905			106,951,172	424,996,081		531,947,253	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,732				715,903		715,903	1
23				1,582		1,582	2
17				846		846	3
3,484				290,089		290,089	4
105				7,246		7,246	5
3,023				250,921		250,921	6
575				44,028		44,028	7
8,942				586,428		586,428	8
9,529				620,450		620,450	9
9,846				661,178		661,178	10
10,251				685,541		685,541	11
5,591				375,857		375,857	12
2,639				172,778		172,778	13
9,929				665,977		665,977	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
10,554				873,206		873,206	1
1,510				105,936		105,936	2
10,615				652,383		652,383	3
8,429				550,300		550,300	4
9,059				564,452		564,452	5
8,476				536,123		536,123	6
4,166				282,140		282,140	7
9,034				605,205		605,205	8
9,988				661,547		661,547	9
26				1,315		1,315	10
				-16		-16	11
10,594				709,981		709,981	12
9,495				785,104		785,104	13
				-18		-18	14
7,773,905			106,951,172	424,996,081		531,947,253	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5				284		284	1
5,449				265,471		265,471	2
8,826				589,451		589,451	3
							4
8,986				742,122		742,122	5
9,833				811,432		811,432	6
1,647				103,143		103,143	7
9,614				792,455		792,455	8
294				18,373		18,373	9
9,911				660,634		660,634	10
67				5,060		5,060	11
-1				-40		-40	12
-2				-74		-74	13
9,914				661,093		661,093	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,331				627,193		627,193	1
7				340		340	2
29				1,812		1,812	3
20				1,043		1,043	4
23				1,427		1,427	5
538				41,207		41,207	6
7				309		309	7
							8
-1				-25		-25	9
-1				-20		-20	10
15				757		757	11
1,196				80,204		80,204	12
							13
2				94		94	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
19,651				1,258,993		1,258,993	1
4				183		183	2
10				476		476	3
9,712				570,590		570,590	4
7,069				476,077		476,077	5
9,886				662,464		662,464	6
9,528				635,169		635,169	7
6,500				435,579		435,579	8
2				119		119	9
65,622				3,740,444		3,740,444	10
9,217				618,139		618,139	11
15				754		754	12
3,805				248,189		248,189	13
8,956				599,678		599,678	14
7,773,905			106,951,172	424,996,081		531,947,253	

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				-8		-8	1
9,655				629,016		629,016	2
9,952				665,428		665,428	3
10,260				685,306		685,306	4
9,274				765,364		765,364	5
538				41,172		41,172	6
3,312				273,758		273,758	7
							8
30				1,484		1,484	9
7,899				653,392		653,392	10
3,502				289,648		289,648	11
3,695				303,938		303,938	12
9,311				766,287		766,287	13
558				34,989		34,989	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
12				806		806	1
9,208				760,263		760,263	2
9,135				755,306		755,306	3
9,110				749,807		749,807	4
9,725				652,828		652,828	5
9,925				660,298		660,298	6
111				8,509		8,509	7
-15				-548		-548	8
							9
10				491		491	10
2				101		101	11
				-18		-18	12
8,855				731,310		731,310	13
9,561				642,091		642,091	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,985				564,637		564,637	1
9,412				614,307		614,307	2
9,235				617,774		617,774	3
8,977				740,498		740,498	4
10,511				702,930		702,930	5
4,593				310,986		310,986	6
10,327				689,268		689,268	7
392,571			44,307,453	21,652,148		65,959,601	8
				39,840		39,840	9
14,549			12,748,400	1,332,619		14,081,019	10
			-650	113		-537	11
1,110,251			13,229,738	36,412,046		49,641,784	12
15,356				399,057		399,057	13
				-293,036		-293,036	14
7,773,905			106,951,172	424,996,081		531,947,253	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
			358,200			358,200	1
			12,962			12,962	2
221,745			36,295,069	10,170,276		46,465,345	3
				764		764	4
1,527,800				49,113,514		49,113,514	5
1,733				-44,261		-44,261	6
183				13,590		13,590	7
				-16,687		-16,687	8
1,500				72,000		72,000	9
7,440				247,565		247,565	10
1,387				39,662		39,662	11
495				13,910		13,910	12
54				1,773		1,773	13
63				2,673		2,673	14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				37		37	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
7,773,905			106,951,172	424,996,081		531,947,253	

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Southeastern Power Administration (Kerr)	various	various	OLF
2	Southeastern Power Administration	various	various	OLF
3	Duke Energy Corporation-Revenue Sharing		various	OS
4	Open Access Transmission Service			
5	Brookfield Energy Marketing LP		various	SNF
6	Cargill		various	SF
7	Cargill		various	SNF
8	City of Camden		various	FNO
9	Craven County Wood Energy		various	OS
10	Duke Energy Carolinas		various	SNF
11	Duke Energy Carolinas		various	SF
12	Elizabethtown Power L.L.C.		various	OS
13	Exelon Power Team		various	SNF
14	Fayetteville Public Works Commission		various	FNO
15	Florida Power Corp		various	SNF
16	French Broad Electric Membership		various	FNO
17	Haywood Electric Membership Coroporation		various	FNO
18	Industrial Power Generating Company L.L.C		various	LFP
19	Industrial Power Generating Company L.L.C		various	OS
20	Lumberton Power L.L.C.		various	OS
21	MacQuarie		various	SNF
22	MacQuarie		various	SF
23	Morgan Stanley		various	SNF
24	NC Eastern Municipal Power Agency		various	FNO
25	North Carolina Electric Membership		various	LFP
26	North Carolina Electric Membership		various	SNF
27	North Carolina Electric Membership		various	SF
28	North Carolina Electric Membership		various	FNO
29	North Carolina Municipial Power Agency 1		various	SNF
30	North Carolina Municipial Power Agency 1		various	SF
31	Piedmont Electric Membership Corporation		various	FNO
32	Southern Wholesale		various	SNF
33	Southern Wholesale		various	SF
34	The Energy Authority		various	SNF
	TOTAL			

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Town of Black Creek N.C.		various	FNO
2	Town of Lucama N.C.		various	FNO
3	Town of Sharpsburg N.C.		various	FNO
4	Town of Stantonsburg N.C.		various	FNO
5	Town of Waynesville		various	FNO
6	Town of Winterville		various	FNO
7	Uwharrie		various	OS
8	Westar Energy		various	SNF
9	DEP OATT (FILED 6-1-17) PARTIAL		various	
10	DEP OATT (FILED 6-1-17) PARTIAL		various	
11	Reversal of DEP Revenue for ROE		various	
12	Reversal of FERC Audit Accrual		various	
13	Reversal for QA from 4th Qtr 2016		various	
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
0.00000	0.00000	0.00000	210			1
0.00000	0.00000	0.00000				2
0.00000	0.00000	0.00000				3
0.00000	0.00000	0.00000		1,591,777	1,562,647	4
0.00000	0.00000	0.00000				5
0.00000	0.00000	0.00000				6
0.00000	0.00000	0.00000				7
0.00000	0.00000	0.00000	457			8
0.00000	0.00000	0.00000				9
0.00000	0.00000	0.00000				10
0.00000	0.00000	0.00000				11
0.00000	0.00000	0.00000				12
0.00000	0.00000	0.00000				13
0.00000	0.00000	0.00000	4,347			14
0.00000	0.00000	0.00000				15
0.00000	0.00000	0.00000	922			16
0.00000	0.00000	0.00000	362			17
0.00000	0.00000	0.00000	48			18
0.00000	0.00000	0.00000				19
0.00000	0.00000	0.00000				20
0.00000	0.00000	0.00000				21
0.00000	0.00000	0.00000				22
0.00000	0.00000	0.00000				23
0.00000	0.00000	0.00000	13,020			24
0.00000	0.00000	0.00000	4,500			25
0.00000	0.00000	0.00000				26
0.00000	0.00000	0.00000				27
0.00000	0.00000	0.00000	22,118			28
0.00000	0.00000	0.00000				29
0.00000	0.00000	0.00000				30
0.00000	0.00000	0.00000	272			31
0.00000	0.00000	0.00000				32
0.00000	0.00000	0.00000				33
0.00000	0.00000	0.00000				34
			46,731	**1,591,777**	**1,562,647**	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
0.00000	0.00000	0.00000	32			1
0.00000	0.00000	0.00000	50			2
0.00000	0.00000	0.00000	44			3
0.00000	0.00000	0.00000	51			4
0.00000	0.00000	0.00000	161			5
0.00000	0.00000	0.00000	137			6
0.00000	0.00000	0.00000				7
0.00000	0.00000	0.00000				8
0.00000	0.00000	0.00000				9
0.00000	0.00000	0.00000				10
0.00000	0.00000	0.00000				11
0.00000	0.00000	0.00000				12
0.00000	0.00000	0.00000				13
0.00000	0.00000	0.00000				14
						15
						16
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						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			46,731	**1,591,777**	**1,562,647**	

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,294,797			1,294,797	1
				2
2,156,872			2,156,872	3
				4
3,318		284	3,602	5
154,633		13,826	168,459	6
369,294		35,134	404,428	7
618,224		61,798	680,022	8
		10,500	10,500	9
157,290		4,380	161,670	10
123,472		10,458	133,930	11
		7,200	7,200	12
2,586		222	2,808	13
5,867,185		580,697	6,447,882	14
7,634		645	8,279	15
1,241,510		185,780	1,427,290	16
487,441		66,362	553,803	17
63,213		6,015	69,228	18
		450	450	19
		4,800	4,800	20
137,528		11,673	149,201	21
111,175		9,314	120,489	22
-224			-224	23
17,901,425		1,627,378	19,528,803	24
2,883,067		248,385	3,131,452	25
18,465		1,583	20,048	26
1,725		145	1,870	27
29,596,581		2,498,099	32,094,680	28
1,117,047		98,727	1,215,774	29
709,658		60,005	769,663	30
367,112		64,097	431,209	31
7,054		605	7,659	32
3,381		283	3,664	33
377,718		32,207	409,925	34
68,095,553	**0**	**5,759,079**	**73,854,632**	

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
43,211		8,797	52,008	1
67,829		11,035	78,864	2
60,705		10,362	71,067	3
68,975		11,456	80,431	4
205,123		45,735	250,858	5
185,865		25,574	211,439	6
		5,052	5,052	7
199		16	215	8
464,000			464,000	9
-1,114,000			-1,114,000	10
2,604,000			2,604,000	11
214,425			214,425	12
-989,812			-989,812	13
505,852			505,852	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
68,095,553	**0**	**5,759,079**	**73,854,632**	

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
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32					
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34					
35					
36					
37					
38					
39					
40	TOTAL				

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	04/12/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	LFP	2,296,640	2,347,096			304	304
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,296,640	2,347,096			304	304

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	04/12/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	807,962
2	Nuclear Power Research Expenses	1,313,722
3	Other Experimental and General Research Expenses	89,236
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Service Company Support	-30,871,943
7	Allocated Incentives	10,758
8	Suspense Clearing	-3,676,834
9	Environmental Accrual Adjustment	1,018,264
10	Consultants and Contract Services	1,371,182
11	Labor Accrual	445,526
12	Restricted Stock Units	493,552
13	Other Contracts	12,469
14	Allocated Labor	80,947
15	Travel	115,214
16	Direct Purchase Allocations	175,262
17	Personal Vehicle Mileage Reimbursement	1,924
18	Postage and Freight	18,739
19	Rent	12,286
20	Miscellaneous < $5k	12,288
21	Miscellaneous > $5k	16,654
22	Moving Expenses	1,589,076
23	Dues and Subscriptions to Various Organizations	238,582
24		
25		
26		
27		
28		
29		
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32		
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45		
46	TOTAL	-26,725,134

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	04/12/2018	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			37,982,533		37,982,533
2	Steam Production Plant	101,800,730				101,800,730
3	Nuclear Production Plant	177,563,167				177,563,167
4	Hydraulic Production Plant-Conventional	3,635,836				3,635,836
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	77,820,891				77,820,891
7	Transmission Plant	42,222,261				42,222,261
8	Distribution Plant	214,327,677				214,327,677
9	Regional Transmission and Market Operation					
10	General Plant	16,206,805		7,021		16,213,826
11	Common Plant-Electric					
12	TOTAL	633,577,367		37,989,554		671,566,921

B. Basis for Amortization Charges

Account 404 is the amortization of capitalized software and generating plant relicensing. Intangible plant is amortized over 5 years. The generating plant relicensing is amortized over the remaining life of the license.

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	04/12/2018	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
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Schedule Page: 336 Line No.: 3 Column: f

Depreciation rates do not include nuclear decommissioning amortization. The portion for nuclear decommissioning amortization accrued in 2017 to Account 403 - Depreciation Expense was 13,718,060.

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	04/12/2018	End of 2017/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Annual Charges Assessed by the Federal Energy				
2	Regulatory Commission for the Cost of				
3	Administration of the Federal Power Act:				
4	Project 2206-Blewett-Tillery Hydro				
5	Power Generation				
6	Project 432-Walters Hydro Power Generation				
7	NC Rate Case Amortization (5 years)	595,605		595,605	843,773
8	Annual Charges Assessed by the Federal Energy				
9	Regulatory Commission as required by Section				
10	3401 of the Omnibus Budget Reconciliation				
11	Act of 1986:				
12	FERC Order 472 Annual Charges	1,913,958		1,913,958	
13					
14	Annual Charges Assessed by the NC Utilities				
15	Commission as required by Senate Bill 1320	3,852,770		3,852,770	
16					
17	Annual Charges Assessed by the SC Public				
18	Service Commission	734,074		734,074	
19					
20					
21	SC Rate Case Amortization (5 years)	30,587		30,587	152,935
22					
23					
24	Other	632		632	
25					
26					
27					
28					
29					
30					
31					
32					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	7,127,626		7,127,626	996,708

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
							4
							5
							6
				182.3	595,605	248,168	7
							8
							9
							10
							11
Electric	928	1,913,958					12
							13
							14
Electric	928	3,852,770					15
							16
							17
Electric	928	734,074					18
							19
							20
				182.3	30,587	122,348	21
							22
							23
Electric	928	632					24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
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							39
							40
							41
							42
							43
							44
							45
		6,501,434			626,192	370,516	46

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	04/12/2018	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D, & D Performed Internally:	
2	(3) Distribution	Research & Development Administration Costs
3		
4	(7) Total Cost Incurred	
5		
6	B. Electric R, D, & D Performed Externally:	
7	(1) Electric Power Research Institute	Electric Power Research Institute Memberships
8		EPRI Nuclear Co-Funds
9		EPRI DNP Support
10		Others (less than $50K each)
11		
12	(4) Research Support to Others	Alternative Energy (Advanced Energy Research)
13		
14		
15	(5) Total Cost Incurred	
16		
17		
18		
19		
20		
21		
22		
23		
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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	04/12/2018	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
89,236		930.7	89,236		2
					3
89,236			89,236		4
					5
					6
	6,366,606	Various	6,366,606		7
	753,395	524	753,395		8
	52,405	524	52,405		9
	23,905	Various	23,905		10
					11
	1,313,722	930.8	1,313,722		12
					13
					14
	8,510,033		8,510,033		15
					16
					17
					18
					19
					20
					21
					22
					23
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					37
					38

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	04/12/2018	End of 2017/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	220,824,247		
4	Transmission	8,313,110		
5	Regional Market			
6	Distribution	22,249,984		
7	Customer Accounts	18,097,277		
8	Customer Service and Informational	2,501,299		
9	Sales	4,041,267		
10	Administrative and General	87,254,686		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	363,281,870		
12	Maintenance			
13	Production	166,771,086		
14	Transmission	5,382,017		
15	Regional Market			
16	Distribution	26,796,737		
17	Administrative and General	178,289		
18	TOTAL Maintenance (Total of lines 13 thru 17)	199,128,129		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	387,595,333		
21	Transmission (Enter Total of lines 4 and 14)	13,695,127		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	49,046,721		
24	Customer Accounts (Transcribe from line 7)	18,097,277		
25	Customer Service and Informational (Transcribe from line 8)	2,501,299		
26	Sales (Transcribe from line 9)	4,041,267		
27	Administrative and General (Enter Total of lines 10 and 17)	87,432,975		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	562,409,999	4,343,070	566,753,069
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			

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	04/12/2018	End of 2017/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)	562,409,999	4,343,070	566,753,069
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	143,682,894	13,753,057	157,435,951
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	143,682,894	13,753,057	157,435,951
72	Plant Removal (By Utility Departments)			
73	Electric Plant	23,236,034		23,236,034
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	23,236,034		23,236,034
77	Other Accounts (Specify, provide details in footnote):			
78	Other Work in Progress	2,536,875		2,536,875
79	Other Accounts	3,493,982		3,493,982
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,030,857		6,030,857
96	TOTAL SALARIES AND WAGES	735,359,784	18,096,127	753,455,911

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	04/12/2018	End of 2017/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

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	04/12/2018	End of 2017/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	(114,337)	(78,322)	87,487	106,021
3	Net Sales (Account 447)	122,647	569,628	3,722,500	3,753,943
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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32					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	8,310	491,306	3,809,987	3,859,964

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				41,685	MWH	1,528,060
2	Reactive Supply and Voltage				35,766	MWH	3,176,056
3	Regulation and Frequency Response				151	MWH	7,190
4	Energy Imbalance	54	MWH	1,773	-163	MWH	6,241
5	Operating Reserve - Spinning				151	MWH	10,606
6	Operating Reserve - Supplement				151	MWH	7,579
7	Other						
8	Total (Lines 1 thru 7)	54		1,773	77,741		4,735,732

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	14,902	9	8	9,816	4,707	379			
2	February	11,151	10	8	7,579	3,193	379			
3	March	12,418	16	8	8,380	3,659	379			
4	Total for Quarter 1				25,775	11,559	1,137			
5	April	10,271	29	17	6,904	2,988	379			
6	May	11,111	17	18	7,477	3,255	379			
7	June	12,095	14	17	8,197	3,519	379			
8	Total for Quarter 2				22,578	9,762	1,137			
9	July	13,248	13	17	8,962	3,907	379			
10	August	13,105	18	16	8,669	4,057	379			
11	September	11,771	28	17	7,953	3,439	379			
12	Total for Quarter 3				25,584	11,403	1,137			
13	October	10,799	10	15	7,390	3,030	379			
14	November	10,596	28	8	7,187	3,030	379			
15	December	12,564	29	8	8,399	3,786	379			
16	Total for Quarter 4				22,976	9,846	1,137			
17	Total Year to Date/Year				96,913	42,570	4,548			

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	04/12/2018	End of 2017/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

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	04/12/2018	End of 2017/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	43,270,010
3	Steam	8,654,367			
4	Nuclear	29,504,561	23	Requirements Sales for Resale (See instruction 4, page 311.)	18,060,645
5	Hydro-Conventional	480,797			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,492,081
7	Other	22,753,840			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	61,393,565	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	84,404
10	Purchases	7,773,905	27	Total Energy Losses	2,239,026
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	69,146,166
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,591,777			
17	Delivered	1,562,647			
18	Net Transmission for Other (Line 16 minus line 17)	29,130			
19	Transmission By Others Losses	-50,434			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	69,146,166			

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	5,834,010	382,182	14,407	9	800
30	February	4,973,101	586,670	10,605	10	800
31	March	5,366,363	281,366	11,947	16	800
32	April	4,719,957	215,666	9,711	29	1600
33	May	5,322,373	343,444	10,491	17	1800
34	June	5,991,455	328,032	11,501	14	1700
35	July	6,926,130	387,768	12,590	13	1700
36	August	6,756,121	456,130	12,529	18	1600
37	September	5,839,152	671,838	11,132	28	1700
38	October	5,360,019	557,987	10,173	10	1600
39	November	5,554,442	634,448	9,989	28	800
40	December	6,503,043	646,550	11,978	29	800
41	TOTAL	69,146,166	5,492,081			

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	04/12/2018	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Asheville* (b)	Plant Name: *Cape Fear* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Conv & Full Outdoor
3	Year Originally Constructed	1964	1923
4	Year Last Unit was Installed	1971	1958
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	418.30	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	383	0
7	Plant Hours Connected to Load	87110	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	384	0
10	When Limited by Condenser Water	378	0
11	Average Number of Employees	88	7
12	Net Generation, Exclusive of Plant Use - KWh	1220607000	0
13	Cost of Plant: Land and Land Rights	4400284	0
14	Structures and Improvements	83465317	0
15	Equipment Costs	377693802	0
16	Asset Retirement Costs	400900685	0
17	Total Cost	866460088	0
18	Cost per KW of Installed Capacity (line 17/5) Including	2071.3844	0
19	Production Expenses: Oper, Supv, & Engr	1070671	286
20	Fuel	43772839	-191
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	6606738	273
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2317	0
26	Misc Steam (or Nuclear) Power Expenses	1585663	101443
27	Rents	27797	0
28	Allowances	1736984	19018
29	Maintenance Supervision and Engineering	891907	69
30	Maintenance of Structures	1444095	94227
31	Maintenance of Boiler (or reactor) Plant	5624131	42
32	Maintenance of Electric Plant	3342641	36
33	Maintenance of Misc Steam (or Nuclear) Plant	1559106	34470
34	Total Production Expenses	67664889	249673
35	Expenses per Net KWh	0.0554	0.0000

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Coal				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Barrels	Tons				
38	Quantity (Units) of Fuel Burned	8808	571554	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137510	12697	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	78.300	80.580	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	78.531	73.658	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	13.597	2.901	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.035	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	11932.000	11932.000	0.000	0.000	0.000	0.000

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Roxboro* (b)	Plant Name: *L.V. Sutton* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Full Outdoor
3	Year Originally Constructed	1966	1954
4	Year Last Unit was Installed	1980	1972
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2558.20	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	2474	0
7	Plant Hours Connected to Load	6872	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	2462	0
10	When Limited by Condenser Water	2439	0
11	Average Number of Employees	220	0
12	Net Generation, Exclusive of Plant Use - KWh	6008262000	0
13	Cost of Plant: Land and Land Rights	8105075	0
14	Structures and Improvements	248793289	0
15	Equipment Costs	1880393662	0
16	Asset Retirement Costs	194327790	0
17	Total Cost	2331619816	0
18	Cost per KW of Installed Capacity (line 17/5) Including	911.4298	0
19	Production Expenses: Oper, Supv, & Engr	4227818	2734
20	Fuel	208408477	450
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	8726878	513
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	10279	0
26	Misc Steam (or Nuclear) Power Expenses	6082199	187944
27	Rents	0	0
28	Allowances	3569686	35658
29	Maintenance Supervision and Engineering	3493338	299
30	Maintenance of Structures	3147490	532124
31	Maintenance of Boiler (or reactor) Plant	18455417	180
32	Maintenance of Electric Plant	2615219	24444
33	Maintenance of Misc Steam (or Nuclear) Plant	3420276	233
34	Total Production Expenses	262157077	784579
35	Expenses per Net KWh	0.0436	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Coal				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Barrels	Tons				
38	Quantity (Units) of Fuel Burned	84594	2465133	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138164	12760	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	81.180	79.920	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	79.134	81.042	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	13.637	3.176	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.034	0.034	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10552.000	10552.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *H.B. Robinson* (b)			Plant Name: *Asheville* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1971			1999		
4	Year Last Unit was Installed	1971			2000		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	768.60			418.80		
6	Net Peak Demand on Plant - MW (60 minutes)	801			330		
7	Plant Hours Connected to Load	7752			935		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	797			370		
10	When Limited by Condenser Water	741			320		
11	Average Number of Employees	777			0		
12	Net Generation, Exclusive of Plant Use - KWh	5925833000			94913000		
13	Cost of Plant: Land and Land Rights	1663503			565402		
14	Structures and Improvements	359091596			31683425		
15	Equipment Costs	1080221761			67018957		
16	Asset Retirement Costs	219835396			0		
17	Total Cost	1660812256			99267784		
18	Cost per KW of Installed Capacity (line 17/5) Including	2160.8278			237.0291		
19	Production Expenses: Oper, Supv, & Engr	11657741			272479		
20	Fuel	43458877			8353451		
21	Coolants and Water (Nuclear Plants Only)	4123252			0		
22	Steam Expenses	13519387			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1768597			359462		
26	Misc Steam (or Nuclear) Power Expenses	38896902			1906504		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	18727957			304663		
30	Maintenance of Structures	5755074			532476		
31	Maintenance of Boiler (or reactor) Plant	21485185			0		
32	Maintenance of Electric Plant	12826802			259250		
33	Maintenance of Misc Steam (or Nuclear) Plant	17536604			198767		
34	Total Production Expenses	189756378			12187052		
35	Expenses per Net KWh	0.0320			0.1284		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Nuclear		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MBTUs		MW DAYS	Barrels	MCF	
38	Quantity (Units) of Fuel Burned	61412755	0	749741	58025	795378	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	138363	1034433	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	78.300	4.696	0.000
41	Average Cost of Fuel per Unit Burned	0.000	56.306	0.000	78.980	4.696	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.687	0.000	13.591	4.537	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.007	0.000	0.088	0.088	0.000
44	Average BTU per KWh Net Generation	0.000	10356.000	0.000	12226.000	12226.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Morehead* (b)	Plant Name: *Cape Fear* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed	1968	1969
4	Year Last Unit was Installed	1968	1969
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	17	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Wayne County* (b)			Plant Name: *Smith Energy Complex* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	2000			2001		
4	Year Last Unit was Installed	2009			2011		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	979.70			2244.80		
6	Net Peak Demand on Plant - MW (60 minutes)	606			2163		
7	Plant Hours Connected to Load	728			12195		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	959			2143		
10	When Limited by Condenser Water	857			1845		
11	Average Number of Employees	7			71		
12	Net Generation, Exclusive of Plant Use - KWh	129482000			10229473000		
13	Cost of Plant: Land and Land Rights	4581022			2839730		
14	Structures and Improvements	118751254			106892951		
15	Equipment Costs	260093867			951365642		
16	Asset Retirement Costs	0			0		
17	Total Cost	383426143			1061098323		
18	Cost per KW of Installed Capacity (line 17/5) Including	391.3710			472.6917		
19	Production Expenses: Oper, Supv, & Engr	260121			951256		
20	Fuel	8097626			302072194		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	250554			1032208		
26	Misc Steam (or Nuclear) Power Expenses	1482555			4473117		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	702357			2615414		
30	Maintenance of Structures	215451			785092		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	827804			9518275		
33	Maintenance of Misc Steam (or Nuclear) Plant	2670153			8182019		
34	Total Production Expenses	14506621			329629575		
35	Expenses per Net KWh	0.1120			0.0322		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Barrels	MCF		Barrels	MCF	
38	Quantity (Units) of Fuel Burned	27239	1321744	0	4040	76153558	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137764	1040042	0	140000	1034268	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	71.340	3.943	0.000	0.000	3.959	0.000
41	Average Cost of Fuel per Unit Burned	102.574	3.943	0.000	97.631	3.959	0.000
42	Average Cost of Fuel Burned per Million BTU	17.728	3.791	0.000	16.605	3.828	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.062	0.062	0.000	0.030	0.030	0.000
44	Average BTU per KWh Net Generation	11834.000	11834.000	0.000	7702.000	7702.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *H.F. Lee* (d)	Plant Name: *Mayo* (e)	Plant Name: *H.B. Robinson* (f)	Line No.
Steam	Steam	Steam	1
Full Outdoor	Full Outdoor	Full Outdoor	2
1951	1983	1960	3
1962	1983	1960	4
0.00	763.20	0.00	5
0	716	0	6
0	3972	0	7
0	0	0	8
0	746	0	9
0	727	0	10
0	86	0	11
0	1425527000	-29000	12
0	14994716	0	13
0	170378648	0	14
0	1027316608	0	15
0	136942519	0	16
0	1349632491	0	17
0	1768.3864	0	18
3962	1729176	4685	19
364	54024615	0	20
0	0	0	21
11	3480320	-7	22
0	0	0	23
0	0	0	24
0	461	0	25
187	1504831	-7320	26
0	0	0	27
834	1259069	-493	28
187	780520	434	29
336706	3414345	22604	30
3115	6581742	1526	31
96	362016	3310	32
8386	2819072	9136	33
353848	75956167	33875	34
0.0000	0.0533	-1.1681	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Oil	Coal					36
			Barrels	Tons					37
0	0	0	37761	630441	0	0	0	0	38
0	0	0	137714	12843	0	0	0	0	39
0.000	0.000	0.000	80.910	80.790	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	78.617	81.010	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	13.592	3.154	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.038	0.038	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	11513.000	11513.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *W.H. Weatherspoon* (d)			Plant Name: *Brunswick* (e)			Plant Name: *Harris* (f)			Line No.
		Steam			Nuclear			Nuclear	1
		Outdoor Boiler			Conventional			Conventional	2
		1949			1975			1987	3
		1952			1977			1987	4
		0.00			2003.20			950.90	5
		0			1912			981	6
		0			8760			8708	7
		0			0			0	8
		0			1928			973	9
		0			1870			928	10
		0			1010			836	11
		0			15370155000			8208573000	12
		0			4060633			62514104	13
		0			809861226			1881025651	14
		0			2122658968			2087295288	15
		0			305308377			350994010	16
		0			3241889204			4381829053	17
		0			1618.3552			4608.0861	18
		1535			18108557			11270271	19
		17231			105597735			56677842	20
		0			10089887			7038264	21
		81			22213248			10156173	22
		0			0			0	23
		0			0			0	24
		0			2470516			1678318	25
		28764			67255667			58723498	26
		0			0			0	27
		5664			0			0	28
		34			41362836			15428119	29
		61648			5956360			4566970	30
		20			31709544			10680163	31
		17			20509564			7783049	32
		796			24383812			10343497	33
		115790			349657726			194346164	34
		0.0000			0.0227			0.0237	35
				Nuclear			Nuclear		36
			MBTUs		MW DAYS	MBTUs		MW DAYS	37
0	0	0	163057972	0	1990648	86289074	0	1053436	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	51.848	0.000	0.000	53.612	0.000	41
0.000	0.000	0.000	0.000	0.633	0.000	0.000	0.655	0.000	42
0.000	0.000	0.000	0.000	0.007	0.000	0.000	0.007	0.000	43
0.000	0.000	0.000	0.000	10609.000	0.000	0.000	10512.000	0.000	44

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	04/12/2018	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Blewett* (d)			Plant Name: *H.B. Robinson* (e)			Plant Name: *L.V. Sutton* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbine			1
Conventional						Conventional			2
1971			1968			1968			3
1971			1968			2017			4
70.00			0.00			921.30			5
47			0			2578			6
16			0			8170			7
0			0			0			8
68			0			793			9
52			0			756			10
7			0			66			11
-174000			0			4674318000			12
0			0			1208226			13
979564			0			13372971			14
12481298			0			623368187			15
0			0			0			16
13460862			0			637949384			17
192.2980			0			692.4448			18
10855			19			1193986			19
93428			0			162246176			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
4743			48			366070			25
74280			2132			2331247			26
0			0			0			27
0			0			0			28
35109			12			1271494			29
234827			23			1066717			30
0			0			0			31
56750			0			1797335			32
166241			0			2636198			33
676233			2234			172909223			34
-3.8864			0.0000			0.0370			35
Oil						Oil	Gas		36
Barrels						Barrels	MCF		37
890	0	0	0	0	0	2188	32224043	0	38
140492	0	0	0	0	0	138786	1034249	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.024	0.000	40
98.376	0.000	0.000	0.000	0.000	0.000	117.729	5.024	0.000	41
16.676	0.000	0.000	0.000	0.000	0.000	20.201	4.858	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.035	0.035	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	7133.000	7133.000	0.000	44

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	04/12/2018	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Darlington* (d)			Plant Name: *H.F. Lee* (e)			Plant Name: *W.H. Weatherspoon* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbine			1
Conventional			Conventional			Conventional			2
1974			1968			1970			3
1997			2012			1971			4
979.00			1068.00			163.00			5
437			1009			119			6
827			8706			24			7
0			0			0			8
911			1047			164			9
714			888			124			10
0			72			6			11
77056000			7293048000			-262000			12
50044			673304			84323			13
8702193			23411651			3568977			14
126164680			668950074			20039380			15
0			0			0			16
134916917			693035029			23692680			17
137.8109			648.9092			145.3539			18
322379			409649			30698			19
7768858			222087749			198551			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
91448			1021633			13390			25
1192086			2381569			247838			26
0			0			0			27
0			0			0			28
567607			1231373			92272			29
177558			1875286			95859			30
0			0			0			31
1308213			1658716			934490			32
873104			880470			302951			33
12301253			231546445			1916049			34
0.1596			0.0317			-7.3132			35
Oil	Gas		Oil	Gas		Oil			36
Barrels	MCF		Barrels	MCF		Barrels			37
43400	855359	0	81	50799431	0	2070	0	0	38
138015	1031467	0	137641	1037777	0	139971	0	0	39
70.870	3.958	0.000	71.340	4.370	0.000	0.000	0.000	0.000	40
99.100	3.958	0.000	101.137	4.370	0.000	88.608	0.000	0.000	41
17.096	3.837	0.000	17.490	4.211	0.000	15.075	0.000	0.000	42
0.100	0.100	0.000	0.030	0.030	0.000	0.000	0.000	0.000	43
14715.000	14715.000	0.000	7229.000	7229.000	0.000	0.000	0.000	0.000	44

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	04/12/2018	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: 1 Column: c
Cape Fear coal units 3,4,5 & 6 were retired on October 1, 2012.

Schedule Page: 403 Line No.: 1 Column: d
Lee coal units 1,2 & 3 were retired on September, 15 2012.

Schedule Page: 403 Line No.: 1 Column: f
Robinson coal unit 1 was retired on October 1, 2012.

Schedule Page: 402 Line No.: 20 Column: b
Asheville Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 20 Column: c
Cape Fear Steam Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: d
HF Lee Steam Total fuel costs include Fuel Handling and Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: e
Mayo Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 1 Column: c
Sutton Steam unit 3 was retired on November 3, 2013; units 1 & 2 were retired December 31, 2013.

Schedule Page: 403.1 Line No.: 1 Column: d
Weatherspoon fossil steam units were retired on October 1, 2011.

Schedule Page: 403.1 Line No.: 2 Column: e
Brunswick Nuclear Plant contains two boiling water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 403.1 Line No.: 2 Column: f
Harris Nuclear Plant contains one pressurized water reactor. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 402.1 Line No.: 20 Column: b
Roxboro Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 20 Column: c
Sutton Steam Total fuel costs include Fuel Handling.
Accounts 501007, 501008, and 501009 for Coal Ash Beneficial Reuse in the amount of $31,108,974 are excluded.

Schedule Page: 403.1 Line No.: 20 Column: d
W.H, Weatherspoon Total fuel costs include Fuel Handling and Sale of Fly Ash.
Accounts 501007, 501008, and 501009 for Coal Ash Beneficial Reuse in the amount of $1,425,582 are excluded.

Schedule Page: 402.2 Line No.: 1 Column: b
H.B. Robinson Nuclear Plant contains one pressurized water reactor. The nuclear fuel assemblies in the reactor contain enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 402.2 Line No.: 1 Column: c
All Gas Turbine Plants listed on pages 402-403 are peaking plants with the exception of Richmond which includes two combined cycle units (intermediate) and five gas tubine units (peaking) and Lee which includes one combined cycle unit (intermediate) which became commercial on December 31, 2012 and four gas tubine units (peaking) whcih retired October 1, 2012. (refer to instruction 10)

Schedule Page: 403.2 Line No.: 1 Column: e

Robinson CT unit 3 was retired April 1, 2013.

Schedule Page: 403.2 Line No.: 20 Column: f

Sutton Gas Turbine now includes Sutton CT4 and CT5 with in service date of July 8, 2017.

Schedule Page: 402.3 Line No.: 1 Column: b

Morehead CT was retired on October 1, 2012.

Schedule Page: 402.3 Line No.: 1 Column: c

Cape Fear CT unit 2B was retired on October 1, 2012. Cape Fear CT units 1A, 1B, and 2A were retired on April 1, 2013.

Schedule Page: 403.3 Line No.: 1 Column: d

Darlington CT unit 11 was retired on November 8, 2015.

Schedule Page: 403.3 Line No.: 1 Column: e

Lee CT Units 1,2,3, and 4 were retired on October 1, 2012. Lee Combined Cycle (CC) units CT1A, CT1B, CT1C, and ST1 were placed into service on December 31, 2012.

Schedule Page: 402 Line No.: 41 Column: b2

Asheville Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 41 Column: e2

Mayo Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 43 Column: b1

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: b2

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: e1

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: e2

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: b1

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: b2

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: e1

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: e2

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 41 Column: b2

Roxboro Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 43 Column: b1

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 43 Column: b2

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 44 Column: b1

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 44 Column: b2

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: c1

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: c2

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: f1

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: f2

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: c1

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: c2

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: f1

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: f2

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: d1

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: d2

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: e1

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: e2

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: d1

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: d2

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: e1

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: e2

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: b1

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: b2

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: c1

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: c2

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: b1

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: b2

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: c1

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: c2

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

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	04/12/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Blewett Hydro (b)	FERC Licensed Project No. 0 Plant Name: Tillery Hydro (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1912	1928
4	Year Last Unit was Installed	1912	1960
5	Total installed cap (Gen name plate Rating in MW)	24.60	84.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	47	89
7	Plant Hours Connect to Load	8,752	2,675
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	27	84
10	(b) Under the Most Adverse Oper Conditions	27	84
11	Average Number of Employees	7	7
12	Net Generation, Exclusive of Plant Use - Kwh	84,023,000	117,835,000
13	Cost of Plant		
14	Land and Land Rights	500,333	1,151,690
15	Structures and Improvements	4,503,278	4,758,682
16	Reservoirs, Dams, and Waterways	8,275,322	7,647,692
17	Equipment Costs	24,351,289	17,856,741
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	235,619	206,802
20	TOTAL cost (Total of 14 thru 19)	37,865,841	31,621,607
21	Cost per KW of Installed Capacity (line 20 / 5)	1,539.2618	376.4477
22	Production Expenses		
23	Operation Supervision and Engineering	519,790	710,115
24	Water for Power	27,982	34,518
25	Hydraulic Expenses	2,322	-420,060
26	Electric Expenses	16,226	55,384
27	Misc Hydraulic Power Generation Expenses	213,371	252,521
28	Rents	0	0
29	Maintenance Supervision and Engineering	24,801	83,017
30	Maintenance of Structures	43,620	26,529
31	Maintenance of Reservoirs, Dams, and Waterways	89,758	755,387
32	Maintenance of Electric Plant	239,892	200,660
33	Maintenance of Misc Hydraulic Plant	929,341	461,788
34	Total Production Expenses (total 23 thru 33)	2,107,103	2,159,859
35	Expenses per net KWh	0.0251	0.0183

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: Walters Hydro (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage			1
Conventional			2
1930			3
1930			4
108.00	0.00	0.00	5
189	0	0	6
8,744	0	0	7
			8
113	0	0	9
113	0	0	10
7	0	0	11
274,882,000	0	0	12
			13
712,606	0	0	14
3,346,666	0	0	15
31,078,452	0	0	16
19,618,996	0	0	17
8,258	0	0	18
94,496	0	0	19
54,859,474	0	0	20
507.9581	0.0000	0.0000	21
			22
774,546	0	0	23
0	0	0	24
830	0	0	25
29,047	0	0	26
325,442	0	0	27
0	0	0	28
133,255	0	0	29
184,677	0	0	30
444,919	0	0	31
164,308	0	0	32
411,202	0	0	33
2,468,226	0	0	34
0.0090	0.0000	0.0000	35

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	04/12/2018	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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	04/12/2018	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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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	04/12/2018	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Marshall Hydro	1910	5.00	3.0	4,057,000	13,295,988
2						
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7						
8						
9						
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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	04/12/2018	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
265,998	46,384		181,269			1
						2
						3
						4
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						7
						8
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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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Cumberland	Richmond	500.00	500.00	T	56.62		1
2	Cumberland	Wake	500.00	500.00	T	67.26		1
3	Durham	Wake	500.00	500.00	T	27.90		1
4	Mayo	Durham	500.00	500.00	T	45.41		1
5	Mayo	Person	500.00	500.00	T	9.94		1
6	Richmond	Newport (DPC)	500.00	500.00	T	32.69		1
7	Wake	Heritage (VEPCO)	500.00	500.00	T	52.60		1
8	Tot. 500kV Lines							
9	Apex US 1	Cary Regency Park	230.00	230.00	S-HFR	6.95		1
10	Asheboro	Biscoe	230.00	230.00	S-HFR	0.18		1
11	Asheboro	Biscoe	230.00	230.00	W-HFR	25.65		1
12	Asheboro	DPC Pleasant Garden	230.00	230.00	S-HFR	18.48		1
13	Asheboro	Siler City	230.00	230.00	W-HFR	8.94		1
14	Asheboro	Siler City	230.00	230.00	S-HFR	1.10		1
15	Asheboro	Siler City	230.00	230.00	C-HFR	15.69		1
16	Asheville Plant	Enka	230.00	230.00	DC S-TWR	6.62		2
17	Asheville Plant	Enka	230.00	230.00	S-SP	0.47		1
18	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	DC-T	0.18		2
19	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	W-H Fr.	3.43		1
20	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	W-H Fr.	3.43		1
21	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	DC-T	0.18		2
22	Aurora	Aurora PCS (Black)	230.00	230.00	W-H Fr.	2.18		1
23	Aurora	Aurora PCS (Black)	230.00	230.00	DC S-HFR	5.49		2
24	Aurora	Aurora PCS (Black)	230.00	230.00	S-SP	0.28		1
25	Aurora	Aurora PCS (White)	230.00	230.00	DC S-HFR	5.47		2
26	Aurora	Aurora PCS (White)	230.00	230.00	S-SP	0.25		1
27	Aurora	Aurora PCS (White)	230.00	230.00	W-H Fr.	2.20		1
28	Aurora	Greenville	230.00	230.00	DC-T	1.78		2
29	Aurora	Greenville	230.00	230.00	W-H Fr.	36.82		1
30	Aurora	New Bern	230.00	230.00	W-H Fr.	27.75		1
31	Barnard Creek	Town Creek (Overhead)	230.00	230.00	DC-T	1.15		2
32	Barnard Creek	Town Creek (Overhead)	230.00	230.00	W-HFR	0.41		1
33	Barnard Creek	Wilmington Corning Sw Sta	230.00	230.00	W-HFR	3.33		1
34	Barnard Creek	Wilmington Corning Sw Sta	230.00	230.00	S-SP	7.04		1
35	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	7.31		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Biscoe	Rockingham	230.00	230.00	S-HFR	0.77		1
2	Biscoe	Rockingham	230.00	230.00	W-HFR	36.23		1
3	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	S-HFR	1.21		1
4	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	DC-T	1.15		2
5	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	W-H Fr.	24.43		1
6	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	S-SP	7.21		1
7	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	C-SP	0.70		1
8	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	DC-T	0.17		2
9	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	W-H Fr.	29.85		1
10	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	S-HFR	1.13		1
11	Brunswick Plant Unit #1	Jacksonville	230.00	230.00	W-H Fr.	75.21		1
12	Brunswick Plant Unit #2	Town Creek	230.00	230.00	S-HFR	1.36		1
13	Brunswick Plant Unit #2	Town Creek	230.00	230.00	W-HFR	13.31		1
14	Brunswick Plant Unit #1	Weatherspoon Plant	230.00	230.00	DC-T	0.28		2
15	Brunswick Plant Unit #1	Weatherspoon Plant	230.00	230.00	W-H Fr.	77.65		1
16	Brunswick Plant Unit #2	Delco (West)	230.00	230.00	W-H Fr.	30.35		1
17	Brunswick Plant Unit #2	Delco (West)	230.00	230.00	S-H Fr.	1.08		1
18	Brunswick Plant Unit #2	Wallace	230.00	230.00	W-H Fr.	53.57		1
19	Brunswick Plant Unit #2	Wallace	230.00	230.00	S-H Fr.	1.25		1
20	Brunswick Plant Unit #2	Whiteville	230.00	230.00	W-H Fr.	47.74		1
21	Brunswick Plant Unit #2	Whiteville	230.00	230.00	S-H Fr.	1.07		1
22	Brunswick Plant Unit #1	Brunswick Plt Bus 1A Cap Bk	230.00	230.00	S-HFR	0.12		1
23	Brunswick Plant Unit #1	Brunswick Plt Bus 1B Cap Bk	230.00	230.00	S-HFR	0.08		1
24	Brunswick Plant Unit #2	Brunswick Plt Bus 2A Cap Bk	230.00	230.00	S-HFR	0.12		1
25	Brunswick Plant Unit #2	Brunswick Plt Bus 2B Cap Bk	230.00	230.00	S-HFR	0.08		1
26	Cane River	Nagel East & West(APCO)	230.00	230.00	DC-T	15.01		2
27	Cane River	Craggy	230.00	230.00	S-H Fr.	26.39		1
28	Cape Fear Plant	Cape Fear Plant Cap Bank	230.00	230.00	W-HFR	0.10		1
29	Cape Fear Plant	Harris Plant (North)	230.00	230.00	W-H Fr.	7.12		1
30	Cape Fear Plant	Harris Plant (North)	230.00	230.00	S-H Fr.	0.25		1
31	Cape Fear Plant	Harris Plant (South)	230.00	230.00	W-H Fr.	6.14		1
32	Cape Fear Plant	Harris Plant (South)	230.00	230.00	S-H Fr.	0.38		1
33	Cape Fear Plant	Jonesboro	230.00	230.00	W-H Fr.	10.10		1
34	Cape Fear Plant	West End	230.00	230.00	DC-T	0.24		2
35	Cape Fear Plant	West End	230.00	230.00	W-H Fr.	37.30		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Cary Regency Park	Method	230.00	230.00	DC-SSP	0.26		2
2	Cary Regency Park	Method	230.00	230.00	S-SP	4.49		1
3	Cary Regency Park	Method	230.00	230.00	W-H Fr.	4.00		1
4	Cary Regency Park	RTP	230.00	230.00	S-HFR	11.03		1
5	Castle Hayne	Folkstone	230.00	230.00	S-HFR	0.10		1
6	Castle Hayne	Folkstone	230.00	230.00	W-H Fr.	24.90		1
7	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	S-SP	0.45		1
8	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	W-HFR	5.12		1
9	Clinton	Erwin	230.00	230.00	S-SP	1.76		1
10	Clinton	Erwin	230.00	230.00	W-H Fr.	32.03		1
11	Clinton	Erwin	230.00	230.00	S-HFR	0.52		1
12	Clinton	Mt Olive	230.00	230.00	S-HFR	0.27		1
13	Clinton	Mt. Olive	230.00	230.00	S-SP	14.22		1
14	Clinton	Wallace	230.00	230.00	W-H Fr.	36.68		1
15	Concord	East Danville (AEP)	230.00	230.00	S-HFR	1.21		1
16	Concord	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2
17	Concord	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2
18	Cumberland	Delco	230.00	230.00	W-H Fr.	54.40		1
19	Cumberland	Fayetteville (North)	230.00	230.00	DC-SSP	5.16		2
20	Cumberland	Fayetteville (North)	230.00	230.00	W-H Fr.	8.58		1
21	Cumberland	Fayetteville (South)	230.00	230.00	W-H Fr.	8.57		1
22	Cumberland	Fayetteville (South)	230.00	230.00	DC-SSP	5.16		2
23	Cumberland	Whiteville	230.00	230.00	W-H Fr.	40.93		1
24	Durham	East Durham (DPC)	230.00	230.00	DC-SH Fr.	0.75		2
25	Durham	East Durham (DPC)	230.00	230.00	C-H Fr.	0.60		1
26	Durham	East Durham (DPC)	230.00	230.00	W-H Fr.	8.31		1
27	Durham	Falls	230.00	230.00	S-HFR	4.28		1
28	Durham	Falls	230.00	230.00	DC S-HFR	3.35		2
29	Durham	Falls	230.00	230.00	S-SP	2.79		1
30	Durham	Falls	230.00	230.00	W-HFR	4.12		1
31	Durham	Method	230.00	230.00	DC-SSP	1.52		2
32	Durham	Method	230.00	230.00	S-SP	1.56		1
33	Durham	Method	230.00	230.00	W-H Fr.	13.12		1
34	Durham	RTP	230.00	230.00	S-HFR	0.46		1
35	Durham	RTP	230.00	230.00	W-HFR	7.41		1
36					TOTAL	6,256.28		717

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Durham	RTP	230.00	230.00	S-SP	2.23		1
2	Erwin	Fayetteville East	230.00	230.00	W-H Fr.	23.09		1
3	Erwin	Milburnie	230.00	230.00	S-HFR	0.50		1
4	Erwin	Milburnie	230.00	230.00	S-SP	0.71		1
5	Erwin	Milburnie	230.00	230.00	DC-T	1.33		2
6	Erwin	Milburnie	230.00	230.00	W-H Fr.	34.08		1
7	Erwin	Selma	230.00	230.00	S-SP	1.08		1
8	Erwin	Selma	230.00	230.00	W-H Fr.	24.12		1
9	Falls	Milburnie	230.00	230.00	DC-T	10.92		2
10	Falls	Milburnie	230.00	230.00	S-H Fr.	0.32		1
11	Fayetteville	Fayetteville East	230.00	230.00	DC-T	0.97		2
12	Fayetteville	Fayetteville East	230.00	230.00	W-H Fr.	9.82		1
13	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	DC-SSP	0.21		2
14	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.00		1
15	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	W-H Fr.	17.70		1
16	Fayetteville	Raeford	230.00	230.00	DC-SSP	2.08		2
17	Fayetteville	Raeford	230.00	230.00	W-H Fr.	14.86		1
18	Fayetteville	Rockingham	230.00	230.00	W-H Fr.	49.09		1
19	Fayetteville	Rockingham	230.00	230.00	DC S-HFR	2.30		2
20	Fayetteville	Rockingham	230.00	230.00	DC S-SP	2.08		2
21	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S -HFR	6.58		2
22	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.60		1
23	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.27		2
24	Folkstone	Jacksonville	230.00	230.00	W-HFR	20.00		1
25	Folkstone	Jacksonville	230.00	230.00	S-SHFR	0.10		1
26	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	S-SP	9.68		1
27	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	DC S-HFR	2.77		2
28	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	S-HFR	51.32		1
29	Greenville	Everetts (VP)	230.00	230.00	DC-T	1.83		2
30	Greenville	Kinston Dupont	230.00	230.00	S-SFR	24.82		1
31	Greenville	Kinston Dupont	230.00	230.00	S-SP	0.17		1
32	Greenville	Kinston Dupont	230.00	230.00	DC S-SP	0.33		2
33	Greenville	Wilson	230.00	230.00	W-H Fr.	33.69		1
34	Greenville	Wilson	230.00	230.00	S-HFR	0.30		1
35	Harris Plant	Siler City	230.00	230.00	S-H Fr.	1.44		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Harris Plant	Siler City	230.00	230.00	W-H Fr.	30.04		1
2	Harris Plant	Apex US #1	230.00	230.00	W-H Fr.	3.13		1
3	Harris Plant	Apex US #1	230.00	230.00	S-HFR	0.87		1
4	Harris Plant	Erwin	230.00	230.00	S-HFR	0.27		1
5	Harris Plant	Erwin	230.00	230.00	W-HFR	29.50		1
6	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	DC-SSP	1.15		2
7	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	S-H Fr.	0.20		1
8	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	W-H Fr.	34.30		1
9	Harris Plant	RTP	230.00	230.00	S-SP	17.25		1
10	Harris Plant	RTP	230.00	230.00	S-HFR	3.35		1
11	Harris Plant	Wake	230.00	230.00	S-SP	5.39		1
12	Harris Plant	Wake	230.00	230.00	S-H Fr.	32.43		1
13	Harris Plant	Harris Plt Start-Up Tran 1A	230.00	230.00	S-SP	0.17		1
14	Harris Plant	Harris Plt Start-Up Tran 1B	230.00	230.00	S-HFR	0.28		1
15	Havelock	Jacksonville	230.00	230.00	DC-T	5.61		2
16	Havelock	Jacksonville	230.00	230.00	W-H Fr.	32.64		1
17	Havelock	Morehead Wildwood	230.00	230.00	DC-SSP	0.27		2
18	Havelock	Morehead Wildwood	230.00	230.00	W-H Fr.	14.82		1
19	Havelock	Morehead Wildwood	230.00	230.00	S-SP	0.23		1
20	Havelock	New Bern	230.00	230.00	DC-T	0.13		2
21	Havelock	New Bern	230.00	230.00	W-H Fr.	23.34		1
22	Havelock Sub	Havelock Cap Bank	230.00	230.00	S-HFR	0.07		1
23	Henderson	Person	230.00	230.00	DC-T	2.46		2
24	Henderson	Person	230.00	230.00	W-H Fr.	37.47		1
25	Jacksonville	Jacksonville SVC	230.00	230.00	S-HFR	0.10		1
26	Jacksonville	New Bern	230.00	230.00	W-H Fr.	29.92		1
27	Jacksonville	New Bern	230.00	230.00	S-HFR	0.61		1
28	Jacksonville	Wallace	230.00	230.00	W-H Fr.	30.82		1
29	Kinston Dupont	Wommack	230.00	230.00	S-SP	0.14		1
30	Kinston Dupont	Wommack	230.00	230.00	S-HFR	19.06		1
31	Laurinburg	Richmond Sub	230.00	230.00	C-SP	3.32		1
32	Laurinburg	Richmond Sub	230.00	230.00	W-H Fr.	17.12		1
33	Lee CC Plant	Lee Sub	230.00	230.00	S-HFR	0.87		1
34	Lee Sub	Milburnie	230.00	230.00	S-SP	0.43		1
35	Lee Sub	Milburnie	230.00	230.00	W-H Fr.	38.15		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Lee Sub	Milburnie	230.00	230.00	DC-T	1.36		2
2	Lee Sub	Milburnie	230.00	230.00	S-HFR	0.23		1
3	Lee Sub	Mt. Olive	230.00	230.00	S-HFR	0.23		1
4	Lee Sub	Mt. Olive	230.00	230.00	S-SP	10.39		1
5	Lee Sub	Mt. Olive	230.00	230.00	DC S-HFR	3.21		2
6	Lee Sub	Selma	230.00	230.00	S-SP	0.24		1
7	Lee Sub	Selma	230.00	230.00	W-H Fr.	16.54		1
8	Lee Sub	Wommack (North)	230.00	230.00	W-H Fr.	30.37		1
9	Lee Sub	Wommack (South)	230.00	230.00	S-HFR	29.45		1
10	Lilesville	DPC Oakboro (Black)	230.00	230.00	S-HFR	0.30		1
11	Lilesville	DPC Oakboro (Black)	230.00	230.00	DC-T	24.40		2
12	Lilesville	DPC Oakboro (White)	230.00	230.00	S-HFR	0.32		1
13	Lilesville	DPC Oakboro (Whilte)	230.00	230.00	DC-T	24.38		2
14	LIlesville	Rockingham (Black)	230.00	230.00	S-HFR	10.36		1
15	Lilesville	Rockingham (White)	230.00	230.00	S-HFR	10.35		1
16	Lilesville	Rockingham (South)	230.00	230.00	S-HFR	12.70		1
17	Marion	Whiteville	230.00	230.00	S-SP	14.49		1
18	Marion	Whiteville	230.00	230.00	S-HFR	2.38		1
19	Marion	Whiteville	230.00	230.00	DC S-HFR	5.04		2
20	Method	East Durham (DPC)	230.00	230.00	DC S HFR.	0.77		2
21	Method	East Durham (DPC)	230.00	230.00	S-SP	4.36		1
22	Method	East Durham (DPC)	230.00	230.00	C-HFR	0.55		1
23	Method	East Durham (DPC)	230.00	230.00	W-HFR	14.17		1
24	Method	East Durham (DPC)	230.00	230.00	S-HFR	0.55		1
25	Method	East Durham (DPC)	230.00	230.00	DC S-SP	1.53		2
26	Method	Milburnie	230.00	230.00	DC S-SP	3.64		2
27	Method	Milburnie	230.00	230.00	S-SP	3.79		1
28	Method	Milburnie	230.00	230.00	W-SP	5.31		1
29	Milburnie	Person	230.00	230.00	DC-T	58.66		2
30	Milburnie	Person	230.00	230.00	S-H Fr.	0.49		1
31	Milburnie	Person	230.00	230.00	W-H Fr.	0.49		1
32	Milburnie	Wake	230.00	230.00	W-H Fr.	7.00		1
33	New Bern	Wommack (North)	230.00	230.00	S-H Fr.	2.57		1
34	New Bern	Wommack (North)	230.00	230.00	S-SP	0.14		1
35	New Bern	Wommack (North)	230.00	230.00	W-H Fr.	29.32		1
36					TOTAL	6,256.28		717

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	New Bern	Wommack (South)	230.00	230.00	W-HFR	33.33		1
2	New Bern	Wommack (South)	230.00	230.00	S-HFR	0.54		1
3	Person	Rocky Mount	230.00	230.00	S-HFR	0.13		1
4	Person	Rocky Mount	230.00	230.00	DC-SSP	0.18		2
5	Person	Rocky Mount	230.00	230.00	T	8.59		1
6	Person	Rocky Mount	230.00	230.00	W-H Fr.	69.41		1
7	Person	Rocky Mount	230.00	230.00	DC-T	2.47		2
8	Person	Sedge Hill (VP)	230.00	230.00	W-H Fr.	4.85		1
9	Raeford	Richmond Sub	230.00	230.00	W-H Fr.	35.17		1
10	Richmond Sub	Rockingham (East)	230.00	230.00	S-HFR	0.39		1
11	Richmond Sub	Rockingham (East)	230.00	230.00	W-H Fr.	5.57		1
12	Richmond Sub	Rockingham (West)	230.00	230.00	DC S-HFR	1.21		1
13	Richmond Sub	Rockingham (West)	230.00	230.00	S-HFR	6.63		1
14	Richmond County Plant	Richmond Sub (Black)	230.00	230.00	S-HFR	1.13		1
15	Richmond County Plant	Richmond Sub (White)	230.00	230.00	S-HFR	0.88		1
16	Richmond County Plant	Richmond Sub (Orange	230.00	230.00	S-HFR	1.56		1
17	Robinson Plant	Rockingham	230.00	230.00	DC S-HFR	1.21		2
18	Robinson Plant	Rockingham	230.00	230.00	S-HFR	0.20		1
19	Robinson Plant	Rockingham	230.00	230.00	W-HFR	7.53		1
20	Rockingham	West End (West)	230.00	230.00	DC-T	5.73		2
21	Rockingham	West End (West)	230.00	230.00	W-H Fr.	28.26		1
22	Rockingham	West End (East)	230.00	230.00	DC S-HFR	2.30		2
23	Rockingham	West End (East)	230.00	230.00	S-HFR	29.81		1
24	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC-T	4.74		2
25	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC S-SP	0.30		2
26	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC-T	4.74		2
27	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC S-SP	0.30		2
28	Rocky Mount	Wilson	230.00	230.00	S-SP	0.85		1
29	Rocky Mount	Wilson	230.00	230.00	DC-SSP	8.26		2
30	Rocky Mount	Wilson	230.00	230.00	DC S-HFR	3.68		2
31	Roxboro Plant	East Danville (AEP)	230.00	230.00	S-HFR	1.79		1
32	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2
33	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2
34	Roxboro Plant	Concord	230.00	230.00	S-HFR	0.61		1
35	Roxboro Plant	Falls	230.00	230.00	DC-T	47.89		2
36					TOTAL	6,256.28		717

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Roxboro Plant	Falls	230.00	230.00	C-SP	0.21		1
2	Roxboro Plant	Falls	230.00	230.00	S-H Fr.	0.17		1
3	Roxboro Plant	Falls	230.00	230.00	W-H Fr.	1.55		1
4	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	C-H Fr.	1.65		1
5	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	W-H Fr.	31.99		1
6	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	DC S-HFR	0.76		2
7	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	C-H Fr.	1.71		1
8	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	W-H Fr.	31.98		1
9	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	DC S-HFR	0.77		2
10	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	DC-T	16.66		2
11	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	C-SP	0.22		1
12	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	DC-T	16.66		2
13	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	C-SP	0.22		1
14	Roxboro Plant	Person (Middle)	230.00	230.00	C-H Fr.	0.10		1
15	Roxboro Plant	Person (Middle)	230.00	230.00	T	0.14		1
16	Roxboro Plant	Person (Middle)	230.00	230.00	S-H Fr.	1.83		1
17	Roxboro Plant	Person (Ceffo)	230.00	230.00	C-SP	0.21		1
18	Roxboro Palnt	Person (Ceffo)	230.00	230.00	DC-T	0.15		2
19	Roxboro Plant	Person (Ceffo)	230.00	230.00	W-H Fr.	1.90		1
20	Roxboro Plant	Person (Hyco)	230.00	230.00	T	0.08		1
21	Roxboro Plant	Person (Hyco)	230.00	230.00	W-H Fr.	1.18		1
22	Selma	Wake	230.00	230.00	W-H Fr.	21.00		1
23	Sutton CC Plant	Sutton Plant	230.00	230.00	S-HFR	0.16		1
24	Sutton Plant	Castle Hayne	230.00	230.00	W-H Fr.	13.90		1
25	Sutton Plant	Castle Hayne	230.00	230.00	DC-T	0.11		2
26	Sutton Plant	Delco	230.00	230.00	W-H Fr.	14.57		1
27	Sutton Plant	Delco	230.00	230.00	S-HFR	0.44		1
28	Sutton Plant	Delco			DC-T	0.28		2
29	Sutton Plant	Wallace	230.00	230.00	T	0.45		1
30	Sutton Plant	Wallace	230.00	230.00	W-HFR	31.89		1
31	Wake	Zebulon	230.00	230.00	W-HFR	10.74		1
32	Wake	Zebulon	230.00	230.00	S-HFR	0.49		1
33	Wayne County Plant	Lee Sub	230.00	230.00	S-HFR	0.35		1
34	Weatherspoon Plant	Fayetteville	230.00	230.00	W-HFR	32.55		1
35	Weatherspoon Plant	Fayetteville	230.00	230.00	DC-T	0.97		2
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Weatherspoon Plant	Latta	230.00	230.00	T	0.37		1
2	Weatherspoon Plant	Latta	230.00	230.00	W-H Fr.	18.29		1
3	Weatherspoon Plant	Latta	230.00	230.00	DC-T	0.28		2
4	Weatherspoon Plant	Laurinburg	230.00	230.00	W-H Fr.	31.46		1
5	Weatherspoon Plant	Laurinburg	230.00	230.00	S-H Fr.	0.99		1
6	Wayne County Plant	Lee Substation	230.00	230.00	S-HFR	0.31		1
7	Wilmington Corning SW Sta.	Wilmington Corning Sub. (N)	230.00	230.00	S-SP	0.48		1
8	Wilmington Corning SW Sta.	Wilmington Corning Sub (S)	230.00	230.00	S-SP	0.43		1
9	Wilson	Zebulon	230.00	230.00	W-H Fr.	25.92		1
10	Wilson	Zebulon	230.00	230.00	S-H Fr.	0.46		1
11	Tap Point	Angier	230.00	230.00	W-H Fr.	0.11		1
12	Tap Point	Ansonville	230.00	230.00	S-SP	0.03		1
13	Tap Point	Apex (Bank #1)	230.00	230.00	W-H Fr.	0.01		1
14	Tap Point	Apex (Bank #2)	230.00	230.00	S-HFR	0.01		1
15	Tap Point	Auburn	230.00	230.00	W-H Fr.	0.10		1
16	Tap Point	Aurora PCS Mine POD	230.00	230.00	S-HFR	0.02		1
17	Tap Point	Bahama	230.00	230.00	W-H Fr.	0.06		1
18	Tap Point	Bailey	230.00	230.00	W-H Fr.	1.38		1
19	Tap Point	Bayboro	230.00	230.00	W-H Fr.	2.13		1
20	Tap Point	Benson	230.00	230.00	W-H Fr.	0.01		1
21	Tap Point	Benson PGI	230.00	230.00	W-H Fr.	1.98		1
22	Tap Point	Bladenboro Solar	230.00	230.00	S-HFR	0.09		1
23	Tap Point	Brunswick EMC Bolivia	230.00	230.00	S-HFR	0.02		1
24	Tap Point	Brunswick EMC Daws Crk	230.00	230.00	S-HFR	0.02		1
25	Tap Point	Buies Creek	230.00	230.00	W-HFR	0.06		1
26	Tap Point	Bynum	230.00	230.00	S-HFR	0.06		1
27	Tap Point	Bynum	230.00	230.00	W-HFR	9.26		1
28	Tap Point	Camp Geiger	230.00	230.00	S-SP	1.94		1
29	Tap Point	Camp LeJeune Sub #1	230.00	230.00	W-H Fr.	4.65		1
30	Tap Point	Camp LeJeune Sub #2	230.00	230.00	W-H Fr.	0.04		1
31	Tap Point	Camp LeJeune French Creek	230.00	230.00	S-SP/S-HFR	2.92		1
32	Tap Point	Cary	230.00	230.00	W-H Fr.	0.93		1
33	Tap Point	Cary Evans Road (East)	230.00	230.00	W-H Fr.	0.04		1
34	Tap Point	Cary Evans Road (West)	230.00	230.00	S-HFR	0.04		1
35	Tap Point	Cary Trenton Road	230.00	230.00	S-SP-11	4.34		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Cary Triangle Forest	230.00	230.00	W-H Fr.	0.04		1
2	Tap Point	Catherine Lake	230.00	230.00	W-H Fr.	0.08		1
3	Tap Point	Chocowinity	230.00	230.00	W-H Fr.	0.05		1
4	Tap Point	City of Lumberton POD #3	230.00	230.00	S-SP	0.70		1
5	Tap Point	Clifdale	230.00	230.00	W-H Fr.	0.54		1
6	Tap Point	Concord	230.00	230.00	S-HFR	0.13		1
7	Tap Point	County Line Solar	230.00	230.00	S-HFR	0.08		1
8	Tap Point	Craven County Wood Energy	230.00	230.00	W-H Fr.	1.87		1
9	Tap Point	Dover	230.00	230.00	S-HFR	0.04		1
10	Tap Point	Dudley Georgia Pacific	230.00	230.00	W-H Fr.	2.64		1
11	Tap Point	Eden Solar	230.00	230.00	S-HFR	0.06		1
12	Tap Point	Ellerbe	230.00	230.00	W-H Fr.	0.04		1
13	Tap Point	Fort Bragg Knox St.	230.00	230.00	W-H Fr.	0.08		1
14	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	S-SP	0.47		1
15	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	DC S-HFR	2.75		2
16	Tap Point	Fort Bragg Main	230.00	230.00	S-SP	0.04		1
17	Tap Point	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.07		1
18	Tap Point	Four Oaks (East)	230.00	230.00	S-HFR	0.05		1
19	Tap Point	Four Oaks (West)	230.00	230.00	W-H Fr.	0.07		1
20	Tap Point	Fuquay	230.00	230.00	W-H Fr.	0.48		1
21	Tap Point	Fuquay Bells Lake	230.00	230.00	W-H Fr.	0.15		1
22	Tap Point	Garland	230.00	230.00	W-H Fr.	0.06		1
23	Tap Point	Garner Panther Branch(East)	230.00	230.00	W-H Fr.	0.15		1
24	Tap Point	Garner Panther Branch(West)	230.00	230.00	S-HFR	0.07		1
25	Tap Point	Grantham	230.00	230.00	W-H Fr.	0.10		1
26	Tap Point	Hamlet (North)	230.00	230.00	W-H Fr.	0.02		1
27	Tap Point	Hamlet (South)	230.00	230.00	S-HFR	0.02		1
28	Tap Point	Henderson East	230.00	230.00	W-H Fr.	0.06		1
29	Tap Point	Holly Springs (East)	230.00	230.00	S-HFR	0.11		1
30	Tap Point	Holly Springs (West)	230.00	230.00	S-HFR	0.11		1
31	Tap Point	Holly Springs Industrial	230.00	230.00	S-HFR	0.83		1
32	Tap Point	Hope Mills Rockfish Road	230.00	230.00	W-H Fr.	0.07		1
33	Tap Point	Jacksonville Tarawa	230.00	230.00	W-H Fr.	0.04		1
34	Tap Point	Knightdale Square D	230.00	230.00	W-H Fr.	0.95		1
35	Tap Point	Laurel Hills	230.00	230.00	W-H Fr.	0.03		1
36					TOTAL	6,256.28		717

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Laurinburg City	230.00	230.00	W-H Fr.	0.03		1
2	Tap Point	Leesville Wood Valley	230.00	230.00	W-H Fr.	0.15		1
3	Tap Point	Masonboro	230.00	230.00	S-SP	0.03		1
4	Tap Point	Mayo Plant	230.00	230.00	W-H Fr.	3.06		1
5	Tap Point	Morrisville	230.00	230.00	W-H Fr.	0.11		1
6	Tap Point	NCSU CBC	230.00	230.00	S-HFR	0.20		1
7	Tap Point	New Bern West	230.00	230.00	W-H Fr.	0.04		1
8	Tap Point	New Hill	230.00	230.00	W-H Fr.	0.20		1
9	Tap Point	Newton Grove	230.00	230.00	W-H Fr.	2.13		1
10	Tap Point	Oxford North	230.00	230.00	W-H Fr.	0.92		1
11	Tap Point	Oxford South	230.00	230.00	W-H Fr.	6.30		1
12	Tap Point	Person Sub 230/24kV Bank	230.00	230.00	S-HFR	0.11		1
13	Tap Point	Pitt Greene EMC Farmville	230.00	230.00	S-HFR	0.04		1
14	Tap Point	Pittsboro	230.00	230.00	W-H Fr.	0.03		1
15	Tap Point	Prospect	230.00	230.00	W-H Fr.	0.03		1
16	Tap Point	Raleigh Blue Ridge Road	230.00	230.00	S-SP	0.03		1
17	Tap Point	Raleigh Durham Airport	230.00	230.00	W-H Fr.	0.09		1
18	Tap Point	Raleigh Foxcroft	230.00	230.00	W-H Fr.	0.03		1
19	Tap Point	Raleigh Homestead (North)	230.00	230.00	S-HFR	0.07		1
20	Tap Point	Raleigh Homestead (South)	230.00	230.00	S-HFR	0.07		1
21	Tap Point	Raleigh Leesville Road	230.00	230.00	W-H Fr.	0.04		1
22	Tap Point	Raleigh NCSU Centennial	230.00	230.00	S-SP	0.05		1
23	Tap Point	Raleigh Oakdale	230.00	230.00	S-SP	1.26		1
24	Tap Point	Raleigh Six Forks	230.00	230.00	S-H Fr.	0.07		1
25	Tap Point	Rockingham Aberdeen Road	230.00	230.00	W-H Fr.	0.60		1
26	Tap Point	Rolesville	230.00	230.00	W-H Fr.	5.67		1
27	Tap Point	Rose Hill	230.00	230.00	W-H Fr.	0.16		1
28	Tap Point	Rowan Creek Solar	230.00	230.00	S-HFR	0.07		1
29	Tap Point	Rowland	230.00	230.00	W-H Fr.	6.86		1
30	Tap Point	Roxboro Bowmantown Road	230.00	230.00	S-HFR	0.04		1
31	Tap Point	Roxboro Cogentrix	230.00	230.00	W-H Fr.	0.60		1
32	Tap Point	Rox. Plt Unit #3 C. Tower	230.00	230.00	W-H Fr.	0.24		1
33	Tap Point	Roxboro South	230.00	230.00	W-H Fr.	0.79		1
34	Tap Point	Sanford Deep River	230.00	230.00	W-H Fr.	2.63		1
35	Tap Point	Sanford Deep River	230.00	230.00	S-HFR	0.09		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Tap Point	Sanford Garden Street	230.00	230.00	W-H Fr.	3.25		1
2	Tap Point	Sanford Horner Blvd.	230.00	230.00	W-H Fr.	0.04		1
3	Tap Point	Sandhills Util. Ft. Brg 3rd	230.00	230.00	S-HFR	0.35		1
4	Tap Point	Scotts Hill	230.00	230.00	S-SP	3.37		1
5	Tap Point	Shoe Heel Creek Solar	230.00	230.00	S-HFR	0.08		1
6	Tap Point	Siler City Hwy. 64	230.00	230.00	S-HFR	0.53		1
7	Tap Point	Southport	230.00	230.00	W-H Fr.	1.88		1
8	Tap Point	Southport ADM (West)	230.00	230.00	W-H Fr.	0.48		1
9	Tap Point	Southport Cogentrix	230.00	230.00	W-H Fr.	0.30		1
10	Tap Point	Swansbsoro	230.00	230.00	W-H Fr.	0.07		1
11	Tap Point	Tideland EMC Edwards	230.00	230.00	S-SP	0.61		1
12	Tap Point	Topsail	230.00	230.00	W-H Fr.	1.55		1
13	Tap Point	Town of Apex POD #4	230.00	230.00	S-HFR	0.12		1
14	Tap Point	Town of Farmville	230.00	230.00	S-HFR	0.03		1
15	Tap Point	Turnbull Solar	230.00	230.00	S-HFR	0.07		1
16	Tap Point	Wadesboro	230.00	230.00	S-HFR	0.02		1
17	Tap Point	Wadesboro Bowman School	230.00	230.00	S-HFR	12.98		1
18	Tap Point	Wake Tech	230.00	230.00	S-HFR	0.06		1
19	Tap Point	Warsaw	230.00	230.00	S-SP	0.61		1
20	Tap Point	Warsaw	230.00	230.00	W-H Fr.	2.46		1
21	Tap Point	Warsaw Solar	230.00	230.00	S-HFR	0.06		1
22	Tap Point	Weatherspoon Sub	230.00	230.00	W-H Fr.	0.09		1
23	Tap Point	Wendell	230.00	230.00	W-H Fr.	0.07		1
24	Tap Point	Wilmington Invista	230.00	230.00	W-H Fr.	0.58		1
25	Tap Point	Wilmington Cedar Avenue	230.00	230.00	S-SP	0.21		1
26	Tap Point	Wilmington East	230.00	230.00	W-H Fr.	0.01		1
27	Tap Point	Wilmington Ninth & Orange	230.00	230.00	S-SP	2.01		1
28	Tap Point	Wilmington Ogden (East)	230.00	230.00	W-H Fr.	0.06		1
29	Tap Point	Wilmington Ogden (West)	230.00	230.00	S-HFR	0.06		1
30	Tap Point	Wilmington Praxair	230.00	230.00	W-H Fr.	0.58		1
31	Tap Point	Wilmington BASF	230.00	230.00	W-H Fr.	0.22		1
32	Tap Point	Wilmington Winter Park	230.00	230.00	S-HFR	0.02		1
33	Tap Point	Yanceyville	230.00	230.00	S-SP	10.36		1
34	Barnard Creek	Town Creek	230.00	230.00	UNDERGROU	1.42		1
35	Bennettsville Sw Sta	Laurinburg	230.00	230.00	S-HFR	0.12		1
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	9.90		1
2	Camden	Lugoff(SCPSA)	230.00	230.00	W-H Fr.	5.37		1
3	Darlington County Plant	Bennettsville Sw Sta	230.00	230.00	S-HFR	0.13		1
4	Darlington County Plant	Bennetsville Sw Sta	230.00	230.00	W-HFR	34.06		1
5	Darlington County Plant	Darlington IC Turbine Yard	230.00	230.00	S-HFR	0.20		1
6	Darlington County Plant	Florence	230.00	230.00	S-SP	37.28		1
7	Darlington County Plant	Robinson Plant (South)	230.00	230.00	W-H Fr.	1.71		1
8	Darlington County Plant	Robinson Plant (North)	230.00	230.00	S-HFR	1.67		1
9	Darlington County Plant	South Bethune (SCPSA)	230.00	230.00	W-H Fr.	0.06		1
10	Darlington County Plant	Sumter	230.00	230.00	DC-SSP	5.33		2
11	Darlington County Plant	Sumter	230.00	230.00	W-H Fr.	48.36		1
12	Florence	Kingstree	230.00	230.00	W-H Fr.	49.46		1
13	Florence	Latta	230.00	230.00	W-H Fr.	23.42		1
14	Florence	Latta	230.00	230.00	S-SP	0.17		1
15	Florence	Darlington (SCPSA)	230.00	230.00	W-H Fr.	11.05		1
16	Latta	Marion	230.00	230.00	W-H Fr.	8.43		1
17	Marion	Marion (SCPSA) (North)	230.00	230.00	S-HFR	0.07		1
18	Marion	Marion (SCPSA) (South)	230.00	230.00	S-HFR	0.06		1
19	Marion	Whiteville	230.00	230.00	S-SP	6.60		1
20	Marion	Whiteville	230.00	230.00	W-HFR	14.81		1
21	Robinson Plant	Florence	230.00	230.00	DC-T	1.40		2
22	Robinson Plant	Florence	230.00	230.00	W-H Fr.	38.41		1
23	Robinson Plant	Rockingham	230.00	230.00	S-SP	0.23		1
24	Robinson Plant	Rockingham	230.00	230.00	W-H Fr.	38.95		1
25	Robinson Plant	Rockingham	230.00	230.00	DC-T	1.40		2
26	Robinson Plant	Darlington (SCPSA)	230.00	230.00	DC-T	0.60		2
27	Robinson Plant	Darlington (SCPSA)	230.00	230.00	W-H Fr.	17.95		1
28	Robinson Plant	Sumter	230.00	230.00	W-H Fr.	40.56		1
29	Robinson Plant	Sumter	230.00	230.00	DC-T	0.60		2
30	Sumter	St. Geroge (SCE&G)	230.00	230.00	DC-T	7.26		2
31	Sumter	St. George (SCE&G)	230.00	230.00	W-H Fr.	22.90		1
32	Sumter	Wateree Plant (SCE&G)	230.00	230.00	W-H Fr.	16.58		1
33	Sumter	Wateree Plant (SCE&G)	230.00	230.00	DC-T	7.26		2
34	Weatherspoon	Latta	230.00	230.00	W-HFR	13.45		1
35	Tap Point	Bishopville	230.00	230.00	W-H Fr.	0.16		1
36					TOTAL	6,256.28		717

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Tap Point	Camden 230/23kv Yard	230.00	230.00	W-HFR	0.18		1
2	Tap Point	Cheraw Cash Rd.	230.00	230.00	S-SP	1.08		1
3	Tap Point	Cheraw Reid Park	230.00	230.00	W-H Fr.	5.30		1
4	Tap Point	Dillon North	230.00	230.00	S-SP	3.51		1
5	Tap Point	Dillon Maple	230.00	230.00	W-H Fr.	4.39		1
6	Tap Point	Dovesville Nucor	230.00	230.00	W-H Fr.	6.81		1
7	Tap Point	Elliott	230.00	230.00	W-H Fr.	2.15		1
8	Tap Point	Florence Cashua	230.00	230.00	C-SP	1.30		1
9	Tap Point	Florence Ebenezer	230.00	230.00	W-H Fr.	0.08		1
10	Tap Point	Florence West	230.00	230.00	W-H Fr.	0.03		1
11	Tap Point	Hartsville Segars Mill	230.00	230.00	W-H Fr.	0.06		1
12	Tap Point	Hartsville Talley Metals	230.00	230.00	W-HFR	0.31		1
13	Tap Point	Hartsville Talley Metals	230.00	230.00	S-SP	0.74		1
14	Tap Point	Kingstree North	230.00	230.00	W-H Fr.	0.14		1
15	Tap Point	Lake City	230.00	230.00	W-H Fr.	0.08		1
16	Tap Point	McColl	230.00	230.00	W-H Fr.	0.90		1
17	Tap Point	Olanta	230.00	230.00	W-H Fr.	0.05		1
18	Tap Point	Society Hill	230.00	230.00	W-SP	1.13		1
19	Tap Point	Summerton	230.00	230.00	W-HFR	2.70		1
20	Tap Point	Sumter Alice Drive	230.00	230.00	W-H Fr.	0.30		1
21	Tap Point	Sumter Continental Tire	230.00	230.00	S-HFR	0.31		1
22	Tap Point	Sumter North	230.00	230.00	S-SP	0.73		1
23	Tap Point	Sumter Wedgefield Rd.	230.00	230.00	W-H Fr.	0.05		1
24	Tot. 230kV Lines							
25								
26								
27								
28	Tot. 115kV Lines				Tower and	2,564.22		161
29								
30								
31	Tot. 66kV - 69kV Lines				Tower and	11.92		2
32								
33	Expenses (Columns M & N)							
34								
35	Tot. KV Lines							
36					TOTAL	6,256.28		717

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	6,256.28		717

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590MCMA(B)								1
1590MCMA(B)								2
3-1590MCMA								3
3-1590MCMA								4
1590MCMA(B)								5
2515MCMA(B)								6
2515MCMA(B)								7
	23,557,293	77,529,698	101,086,991					8
1272MCMA(B)								9
1272MCMA								10
1272MCMA								11
2-1590MCMA								12
1272MCMA(B)								13
1272MCMA(B)								14
1272MCMA(B)								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1109MCMA								28
1272&1109MCMA								29
1272MCMA								30
2500MCMA								31
2515MCMA								32
1272&2515MCMA								33
1272MCMA								34
2515MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								1
1272MCMA								2
2515MCMA								3
2500MCMA								4
1272&2515MCMA								5
2515MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
2515MCMA								12
2515MCMA								13
1272MCMA								14
1272MCMA								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
1590MCMA								26
1590MCMA								27
795MCMA								28
2515&1272MCMA(								29
1272MCMA(B)								30
1272MCMA(B)								31
1272MCMA(B)								32
795&1272MCMA(B)								33
1272MCMA								34
1272&2515MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515MCMA								1
2515&1272MCMA								2
1272MCMA(B)								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1590MCMA								12
1590MCMA								13
1272&556MCMA(B)								14
1590MCMA								15
1590MCMA								16
1590MCMA								17
1272MCMA								18
2515MCMA								19
2515MCMA								20
2515MCMA								21
2515MCMA								22
1272&2515MCMA								23
1272MCMA(B)								24
1272MCMA(B)								25
1272MCMA(B)								26
1590MCMA(B)								27
1590MCMA(B)								28
1590MCMA(B)								29
1272MCMA								30
2515MCMA								31
2515MCMA								32
2515&1272MCMA(								33
1272MCMA								34
1272MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1272MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA(B)								13
2515&1272MCMA(								14
1272MCMA(B)								15
1272MCMA(B)								16
1272MCMA(B)								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1590MCMA								21
1590MCMA								22
1590MCMA								23
1272MCMA								24
1272MCMA								25
1590MCMA(B)								26
1590MCMA(B)								27
1590MCMA(B)								28
1109MCMA								29
795MCMA(B)								30
795MCMA(B)								31
795MCMA(B)								32
1272&546MCMA(B)								33
1272MCMA								34
1272MCMA(B)								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515&1272MCMA(								1
1272MCMA(B)								2
1590MCMA(B)								3
1272MCMA(B)								4
1272MCMA(B)								5
1272MCMA(B)								6
1272MCMA(B)								7
1272MCMA(B)								8
1590MCMA(B)								9
1590MCMA(B)								10
1590MCMA(B)								11
1590MCMA(B)								12
795MCMA								13
2515MCMA(B)								14
1272MCMA								15
1272&556MCMA(B)								16
1590MCMA								17
1590MCMA								18
1590MCMA								19
1272MCMA								20
1272MCMA								21
795MCMA								22
1272MCMA								23
1272MCMA								24
795MCMA								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
795MCMA(B)								29
795MCMA(B)								30
2515MCMA								31
2515&1272MCMA(								32
1590MCMA(B)								33
1272MCMA								34
1272MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272MCMA								1
1272MCMA								2
1590MCMA								3
1590MCMA								4
1590MCMA								5
2515&1272MCMA(								6
1272MCMA(B)								7
1272MCMA(B)								8
1272MCMA(B)								9
1272 MCMA								10
1272MCMA								11
1272 MCMA								12
1272MCMA								13
1272 MCMA								14
1272 MCMA								15
2515 MCMA								16
1590MCMA								17
1590MCMA								18
1590MCMA								19
1272MCMA(B)								20
2515MCMA								21
1272MCMA(B)								22
2515&1272MCMA(								23
1272MCMA(B)								24
1272MCMA(B)								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA(B)								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA(B)								9
1272MCMA(B)								10
1272MCMA(B)								11
1590MCMA(B)								12
1590MCMA(B)								13
21590MCMA(B)								14
21590MCMA(B)								15
21590MCMA								16
1590MCMA(B)								17
1590MCMA(B)								18
1272&1590MCMA(								19
1272MCMA								20
1272MCMA								21
2-1590MCMA								22
2-1590MCMA								23
1272MCMA								24
1272MCMA								25
1272MCMA								26
1272MCMA								27
1590MCMA								28
1590MCMA								29
1590MCMA								30
1590MCMA								31
1590MCMA								32
1590MCMA								33
1590MCMA								34
1272MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590MCMA								1
1272MCMA								2
1272&1590MCMA								3
1272MCMA(B)								4
1272MCMA(B)								5
1272MCMA(B)								6
1272MCMA(B)								7
1272MCMA(B)								8
1272MCMA(B)								9
1272MCMA(B)								10
1272MCMA(B)								11
1272MCMA(B)								12
1272MCMA(B)								13
1272MCMA(B)								14
1272MCMA(B)								15
1590MCMA(B)								16
1590MCMA(B)								17
1590MCMA(B)								18
1590MCMA(B)								19
2515MCMA								20
1272&2515MCMA(								21
2515&1272MCMA(								22
1590MCMA								23
1272MCMA								24
1272MCMA								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA(B)								31
1272MCMA(B)								32
1590MCMA(B)								33
1272MCMA								34
1272MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								1
1272MCMA								2
1272MCMA								3
1272&2515MCMA								4
1272MCMA								5
1590MCMA(B)								6
795MCMA								7
795MCMA								8
1272MCMA(B)&251								9
1272MCMA(B)								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
1272MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
1272MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
1272MCMA								23
1272MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1272MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
795MCMA								2
1272MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
1272MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
1272MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
1272MCMA								19
1272MCMA								20
795MCMA								21
1272MCMA								22
795MCMA								23
1272MCMA								24
795MCMA								25
1590MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
1272MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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1590MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
1272MCMA								7
1272MCMA								8
795MCMA								9
795MCMA								10
1590MCMA								11
795MCMA								12
795 MCMA								13
795 MCMA								14
795MCMA								15
795MCMA								16
1590MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
1272MCMA								24
795MCMA								25
1272MCMA								26
1272MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
1272MCMA								32
795MCMA								33
2-2500MCMA								34
2515MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515MCMA								1
1272MCMA								2
2515MCMA								3
2515MCMA								4
1590MCMA								5
1590MCMA								6
2515MCMA								7
2515MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA								14
1272MCMA								15
1590MCMA								16
1272MCMA(B)								17
1272MCMA(B)								18
1590MCMA								19
1590MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
1272MCMA								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
1272MCMA								29
795MCMA								30
795MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
795MCMA								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								1
795MCMA								2
1272MCMA								3
795MCMA								4
795MCMA								5
1272MCMA								6
795MCMA								7
795MCMA								8
1590MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
1590MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
	120,669,278	760,741,331	881,410,609					24
								25
								26
								27
	34,737,768	458,034,936	492,772,704					28
								29
								30
	57,228	4,572,037	4,629,265					31
								32
								33
								34
	179,021,567	1,300,878,002	1,479,899,569					35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
				910,085	11,760,895		12,670,980	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	358,043,134	2,601,756,004	2,959,799,138	910,085	11,760,895		12,670,980	36

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	04/12/2018	End of 2017/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NC 230 kV Lines						
2	TAP POINT	BLADENBORO SOLAR	0.09	S-HFR	1.00	1	1
3	TAP POINT	COUNTY LINE SOLAR	0.08	S-HFR	1.00	1	1
4	TAP POINT	SHOE HEEL CREEK SOLAR	0.08	S-HFR	1.00	1	1
5	TAP POINT	TURNBULL SOLAR	0.07	S-HFR	1.00	1	1
6	TAP POINT	FOUR OAKS	0.05	S-HFR	1.00	1	1
7	TAP POINT	GARNER PANTHER	0.07	S-HFR	1.00	1	1
8	TAP POINT	BRUNSWICK EMC BOLIVIA	0.02	S-HFR	1.00	1	1
9							
10	NC 115 kV Lines						
11	TAP POINT	BULLOCKSVILLE SOLAR	0.07	S-HFR	1.00	1	1
12	TAP POINT	MAXTON SOLAR	0.08	S-HFR	1.00	1	1
13	TAP POINT	SNEEDSBORO SOLAR	0.11	S-HFR	1.00	1	1
14	TAP POINT	CANTON EVERGREEN	0.04	S-HFR	1.00	1	1
15	SUTTON FAST START CT	SUTTON CC PLANT	0.29	S-HFR/S-SP	1.00	1	1
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		1.05		12.00	12	12

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
795	MCMA	FLAT	230		100,014	665,176	97,825	863,015	2
795	MCMA	FLAT	230		166,421	842,921	149,361	1,158,703	3
795	MCMA	FLAT	230		60,271	83,201		143,472	4
795	MCMA	FLAT	230		282,058	765,885		1,047,943	5
1272	MCMA	FLAT	230		84,601	46,612		131,213	6
795	MCMA	FLAT	230		251,260	230,520	705	482,485	7
1272	MCMA	FLAT	230		20,039			20,039	8
									9
									10
336	MCMA	FLAT	115		163,090	292,726		455,816	11
336	MCMA	FLAT	115		210,283	411,469	86,272	708,024	12
336	MCMA	FLAT	115		142,768	720,397		863,165	13
336	MCMA	FLAT	115		232,741	62,623		295,364	14
795	MCMA	FLAT/VERT	115		961,454	86,673		1,048,127	15
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					2,675,000	4,208,203	334,163	7,217,366	44

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	04/12/2018	End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Carolina Substations				
2	------------------				
3	Aberdeen 115kV Aberdeen	D-U	115.00	24.00	
4	Amberly 230 kV, Cary	D-U	230.00	24.00	
5	Angier 230kV Angier	D-U	230.00	24.00	
6	Ansonville 230kV Ansonville	D-U	230.00	23.00	
7	Apex 230kV Apex	D-U	230.00	24.00	
8	Archer Lodge 230kV Johnston Co	D-U	230.00	24.00	
9	Arden 115kV Buncombe County	D-U	115.00	24.00	
10	Asheboro 230kV Asheboro	T-U	230.00	115.00	
11	Asheboro East 115kV Asheboro	D-U	115.00	24.00	
12	Asheboro East 115kV Asheboro	T-U	115.00	12.00	
13	Asheboro North 115kV Asheboro	D-U	115.00	24.00	
14	Asheboro South 115kV Asheboro	D-U	115.00	24.00	
15	Asheboro West 115kV Asheboro	D-U	115.00	24.00	
16	Asheville Bent Creek 115kV Asheville	D-U	115.00	24.00	
17	Asheville Rock Hill 115kV Asheville	D-U	115.00	23.00	
18	Asheville S.E. Plant Asheville	T-A	230.00	115.00	
19	Asheville S.E. Plant Asheville	T-A Gen Step-Up 1	115.00	17.20	
20	Asheville S.E. Plant Asheville	T-A Gen Step-Up 2	115.00	19.00	
21	Asheville S.E. Plant Asheville	T-A Gen Set-Up 3,4	115.00	18.00	
22	Atlantic Beach 115kV Morehead	D-U	115.00	12.00	
23	Avery Creek 115 kV Arden	D-U	115.00	24.00	
24	Auburn 230kV Auburn	D-U	230.00	24.00	
25	Bahama 230kV Durham Co.	D-U	230.00	24.00	
26	Bailey 230kV Bailey	D-U	230.00	24.00	
27	Baldwin 115kV Arden	D-U	115.00	24.00	
28	Barnard Creek 230kV Wilmington	T-U	230.00	115.00	
29	Barnardsville 115kV Barnardsville	D-U	115.00	12.00	
30	Bayboro 230kV Bayboro	D-U	230.00	24.00	
31	Bear Branch, Broadway	D-U	230.00	24.00	
32	Beard 115kV Beard	D-U	115.00	13.00	
33	Beaufort 115kV Beaufort	D-U	115.00	12.00	
34	Beaverdam 115kV Asheville	D-U	115.00	24.00	
35	Belfast 115kV Goldsbsoro	D-U	115.00	23.00	
36	Benson 230kV Benson	D-U	230.00	24.00	
37	Beulaville 115kV Beulaville	D-U	115.00	23.00	
38	Biltmore 115kV Asheville	D-U	115.00	12.00	
39	Biscoe 115kV Biscoe	D-U	115.00	24.00	
40	Biscoe 230kV Bisco	T-U	230.00	115.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Black Mountain 115kV Black Mountain	D-U	115.00	13.00	
2	Bladenboro 115kV Bladenboro	D-U	115.00	24.00	
3	Blewett H.E. Plant Lilesville	T-A Gen Step-Up	115.00	13.20	
4	Blewett H.E. Plant Lilesville	T-A Gen Step-Up	115.00	4.00	
5	Bridgeton 115kV Bridgeton	D-U	115.00	24.00	
6	Brunswick S.E. Plant Wilmington	T-A Gen Step-Up	230.00	24.00	
7	Buies Creek 230kV Buies Creek	D-U	230.00	24.00	
8	Burgaw 115kV Burgaw	D-U	115.00	23.00	
9	Butler Bldg 115kv Laurinburg NC	D-U	115.00	12.00	
10	Bynum 230kV Bynum	D-U	230.00	24.00	
11	Camp Lejeune French Creek 230kV Jacksonville	D-U	230.00	13.80	
12	Candler 115 kV Candler	D-U	115.00	24.00	
13	Candor 115kV Candor	D-U	115.00	24.00	
14	Cane River 230kV Burnsville	T-U	230.00	115.00	
15	Canton 115kV Canton	D-U	115.00	12.00	
16	Cape Fear S.E. Plant Moncure	T-A	230.00	115.00	13.80
17	Caraleigh 230kV Raleigh	D-U	230.00	24.00	
18	Carolina Beach 115kV Carolina Beach	D-U	115.00	24.00	
19	Carthage 115kV Carthage	D-U	115.00	12.00	
20	Cary 230kV Cary	D-U	230.00	23.00	
21	Cary Evans Rd. 230kV Cary	D-U	230.00	24.00	
22	Cary Piney Plains 230kV Cary	D-U	230.00	24.00	
23	Cary Regency Park 230kV Cary	D-U	230.00	23.00	
24	Cary Trenton Road 230 kV Cary	D-U	230.00	24.00	
25	Cary Triangle Forest 230kV Cary	D-U	230.00	23.00	
26	Castalia 230 kV Castalia	D-U	230.00	24.00	
27	Castle Hayne 115kV Wilmington	D-U	115.00	24.00	
28	Castle Hayne 230kV Wilmington	T-U	230.00	115.00	13.80
29	Catherine Lake 230kV Jacksonville	D-U	230.00	24.00	
30	Chadbourn 115kV Chadbourn	D-U	115.00	24.00	
31	Cherry Point #1 115kV Havelock	D-U	115.00	12.00	
32	Cherry Point #2 115kV Havelock	D-U	115.00	12.00	
33	Chestnut Hills 115kV Raleigh	D-U	115.00	24.00	
34	Chocowinity 230kV Chocowinity	D-U	230.00	23.00	
35	Clarkton 115kV Clarkton	D-U	115.00	24.00	
36	Clayton 115kV Clayton	D-U	115.00	24.00	
37	Clayton Industrial 115kV Clayton	D-U	115.00	24.00	
38	Clifdale 230kV Clifdale	D-U	230.00	24.00	
39	Clinton 230kV Clinton	T-U	230.00	115.00	13.80
40	Clinton Ferrell St. 115kV Clinton	D-U	115.00	23.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Clinton (N) 115kV Clinton	D-U	115.00	23.00	
2	Concord 230kV Concord	T-U	230.00	115.00	
3	Craggy 230kV Craggy	T-U	230.00	115.00	
4	Cumberland 500kV Fayetteville	T-U	500.00	230.00	13.80
5	Delco 115kV Delco	D-U	115.00	24.00	
6	Delco 230kV Delco	T-U	230.00	115.00	13.80
7	Dover 230kV Kinston	D-U	230.00	24.00	
8	Duncan 230kV Garner	D-U	230.00	24.00	
9	Dunn 230kV Dunn	D-U	230.00	23.00	
10	Durham 500kV Leesville	T-U	500.00	230.00	13.80
11	Eagle Island 115kV Wilmington	D-U	115.00	24.00	
12	Edmondson 230kV Raleigh	D-U	230.00	24.00	
13	Elizabethtown 115kV Elizabethtown	D-U	115.00	24.00	
14	Elk Mountain 115kV Asheville	D-U	115.00	24.00	
15	Ellerbe 230kV Ellerbe	D-U	230.00	23.00	
16	Elm City 115kV Elm City	D-U	115.00	24.00	
17	Emma 115kV Asheville	D-U	115.00	12.00	
18	Enka 230kV Enka	T-U	230.00	115.00	
19	Enka Sardis Rd. 115kV Enka	D-U	115.00	24.00	
20	Erwin 230kV Erwin	T-U	230.00	115.00	13.80
21	Erwin 230kV Erwin	D-U	115.00	24.00	12.00
22	Erwin 230kV Erwin	D-U	115.00	24.00	
23	Erwin Mills 115kv Erwin	D-U	115.00	12.00	
24	Fair Bluff 115kV Fair Bluff	D-U	115.00	24.00	
25	Fairmont 115kV Fairmont	D-U	115.00	23.00	
26	Fairview 115kV Fairview	D-U	115.00	12.00	
27	Falls 230kV Raleigh	D-U	230.00	24.00	
28	Falls 230kV Raleigh	T-U	230.00	115.00	
29	Farmville 230kV Farmville	D-U	230.00	12.00	
30	Fayetteville 230kV Fayetteville	D-U	115.00	24.00	13.20
31	Fayetteville 230kV Fayetteville	T-U	230.00	115.00	
32	Fayetteville Slocomb 115kV Slocomb	D-U	115.00	12.00	
33	Folkstone 230kV Holly Ridge	T-U	230.00	115.00	
34	Four Oaks 230kV Four Oaks	D-U	230.00	23.00	
35	Ft Bragg Longstreet Rd 230 kV Fort Bragg	D-U	230.00	12.00	
36	Ft. Bragg Main 230kV Fayetteville	D-U	230.00	23.00	
37	Ft. Bragg Main 230kV Fayetteville	D-U	230.00	12.00	
38	Ft. Bragg Woodruff St. 230kV Fayetteville	T-U	230.00	12.00	
39	Ft. Bragg Woodruff St. 230kV Fayetteville	T-U	230.00	115.00	
40	Franklinton Novo 115kV	D-U	115.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Franklinton 115kV Franklinton	D-U	115.00	24.00	
2	Fremont 115kV Fremont	D-U	115.00	12.00	
3	Fuquay 230kV Fuquay	D-U	230.00	23.00	
4	Fuquay Bells Lake 230kV Fuquay	D-U	230.00	23.00	
5	Garland 230kV Garland	D-U	230.00	23.00	
6	Garner 115kV Garner	D-U	115.00	24.00	
7	Garner I-40 230kV Garner	D-U	230.00	24.00	
8	Garner Panther Branch 230kV Wake Co.	D-U	230.00	23.00	
9	Garner Tryon Hills 115kV Garner	D-U	115.00	24.00	
10	Garner White Oak 230kV Garner	D-U	230.00	24.00	
11	Global Trans Park 115kV Kinston	D-U	115.00	23.00	
12	Godwin 115kV Godwin	D-U	115.00	23.00	
13	Goldsboro City 115kV Goldsboro	D-U	115.00	12.00	
14	Goldsboro Hemlock 115kV Goldsboro	D-U	115.00	12.00	
15	Goldsboro Langston 115kV Goldsboro	D-U	115.00	24.00	
16	Goldsboro-Weil 115kV Goldsboro	D-U	115.00	24.00	
17	Grantham 230kV Grantham	D-U	230.00	24.00	
18	Green Level 230kV Green Level	D-U	230.00	24.00	
19	Grifton 115kV Grifton	D-U	115.00	23.00	
20	Hamlet 230kV Hamlet	D-U	230.00	24.00	
21	Havelock 230kV Havelock	D-U	115.00	23.00	
22	Havelock 230kV Havelock	T-U	230.00	115.00	13.80
23	Hazelwood 115kV Hazelwood	D-U	115.00	24.00	
24	Henderson 230kV Henderson	T-U	230.00	115.00	13.20
25	Henderson 230kV Henderson	D-U	115.00	24.00	
26	Henderson East 230kV Henderson	D-U	230.00	24.00	
27	Henderson North 115kV Henderson	D-U	115.00	24.00	
28	Holly Ridge 115kV Holly Ridge	D-U	115.00	23.00	
29	Holly Springs 230kV Holly Springs	D-U	230.00	24.00	
30	Holly Springs Industrial 230kV Holly Springs	D-U	230.00	24.00	
31	Hope Mills Church St. 115kV Hope Mills	D-U	115.00	23.00	
32	Hope Mills Rockfish Rd. 230kV Hope Mills	D-U	230.00	24.00	
33	Jacksonville 230kV Jacksonville	T-U	230.00	115.00	
34	Jacksonville Blue Creek, Jacksonville	D-U	115.00	24.00	
35	Jacksonville City 115kV Jacksonville	D-U	115.00	24.00	
36	Jacksonville Northwoods 115kV Jacksonville	D-U	115.00	23.00	
37	Jacksonville Tarawa 230kV Jacksonville	D-U	230.00	24.00	
38	Jonesboro 230kV Sanford	D-U	230.00	24.00	
39	Kings Bluff 115kV Wilmington	D-U	115.00	23.00	
40	Kinston 115kV Kinston	D-U	115.00	24.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Kinston DuPont 115kV Kinston	D-U	115.00	12.00	
2	Kinston DuPont 230kV Kinston	T-U	230.00	115.00	
3	Knightdale Square D 230kV Knightdale	D-U	230.00	24.00	
4	Knightdale 115kV Knightdale	D-U	115.00	23.00	
5	Kornegay 115kV Kornegay	D-U	115.00	23.00	
6	LaGrange 115kV LaGrange	D-U	115.00	12.00	
7	Lake Junaluska 115kV Lake Junaluska	D-U	115.00	24.00	
8	Lake Wacamaw 115kV Lake Waccamaw	D-U	115.00	24.00	
9	Lakestone 115kV Raleigh	D-U	115.00	12.00	
10	Lakeview 115kv Carthage	D-U	115.00	24.00	
11	Laurel Hill 230kV Laurel Hill	D-U	230.00	23.00	
12	Laurinburg 230kV Laurinburg	T-U	230.00	115.00	13.80
13	Laurinburg 230kV Laurinburg	D-U	115.00	24.00	
14	Laurinburg City 230kV Laurinburg	D-U	230.00	23.00	
15	Lee Combined Cycle Plant	T-A	230.00	115.00	
16	Lee 230kV Goldsboro	T-U	230.00	115.00	
17	Lee 230kV Goldsboro	T-U	115.00	13.80	
18	Leesville Wood Valley 230kV Raleigh	D-U	230.00	24.00	
19	Leicester 115kV Leicester	D-U	115.00	24.00	
20	Leland 115kV Wilmington	D-U	115.00	24.00	
21	Leland Industrial 115kV Leland	D-U	115.00	24.00	
22	Liberty 115kV Liberty	D-U	115.00	23.00	
23	Lillington 115kV Lillington	D-U	115.00	24.00	
24	Littleton 115kV Littleton	D-U	115.00	24.00	
25	Louisburg 115kV Louisburg	D-U	115.00	23.00	
26	Lumberton 115kV Lumberton	D-U	115.00	24.00	
27	Maggie Valley 115kV Maggie Valley	D-U	115.00	24.00	
28	Marshall H.E. Plant Marshall	D-U	115.00	23.00	
29	Marshall H.E. Plant Marshall	T-U Gen Step-Up	23.00	4.00	
30	Masonboro 230kV Wilmington	D-U	230.00	23.00	
31	Maxton 115kV Maxton	D-U	115.00	24.00	
32	Maxton Airport 115kV Maxton	D-U	115.00	23.00	
33	Mayo S.E. Plant Roxboro	T-A Gen Step-Up	500.00	19.90	
34	Method 230kV Raleigh	D-U	115.00	12.00	
35	Method 230kV Raleigh	T-U	230.00	115.00	13.80
36	Micaville 115kV Micaville	D-U	115.00	12.00	
37	Milburnie 230kV Raleigh	D-U	115.00	23.00	
38	Milburnie 230kV Raleigh	T-U	230.00	115.00	13.80
39	Moncure 115kV Moncure	D-U	115.00	24.00	
40	Monte Vista 115kV Asheville	D-U	115.00	23.00	

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1	Mordecai 115kV Raleigh	D-U	115.00	12.00	
2	Morehead 115kV Morehead	D-U	115.00	12.00	
3	Morehead Wildwood 230kV	D-U	115.00	24.00	
4	Morehead Wildwood 230kV Morehead	T-U	230.00	115.00	
5	Morrisville 230kV Morrisville	D-U	230.00	23.00	
6	Mount Gilead 115kV Mount Gilead	D-U	115.00	12.00	
7	Mount Gilead Industrial 115kV Mount Gilead	D-U	115.00	13.00	
8	Mount Olive 115kV Mount Olive	D-U	115.00	12.00	
9	Mount Olive 230kV Mount Olive	T-U	230.00	115.00	
10	Mount Olive West 115kV Mount Olive	D-U	115.00	24.00	
11	Murrayville 230kV New Hanover	D-U	230.00	23.00	
12	Nagel (APCO) 500kV Hawkins, Tn.	T-U	500.00	230.00	13.80
13	Nashville 115kV Nashville	D-U	115.00	23.00	
14	Neuse 115kV Neuse	D-U	115.00	23.00	
15	New Bern 230kV New Bern	T-U	230.00	115.00	13.20
16	New Bern Amital 115kV New Bern	D-U	115.00	12.00	
17	New Bern West 230kV New Bern	D-U	230.00	23.00	
18	New Hill 230kV New Hill	D-U	230.00	23.00	
19	New Hope 115kV Goldsboro	D-U	115.00	23.00	
20	New Salem 115kV Swannanoa	D-U	115.00	12.00	
21	Newport 115kV Newport	D-U	115.00	23.00	
22	Newton Grove 230kV Newton Grove	D-U	230.00	23.00	
23	North River 115kV Beaufort	D-U	115.00	34.50	
24	Oteen 115kV Asheville	D-U	115.00	12.00	
25	Oxford North 230kV Oxford	D-U	230.00	23.00	
26	Oxford South 230kV Oxford	D-U	230.00	23.00	
27	Pembroke 115kV Pembroke	D-U	115.00	23.00	
28	Person 500kV Roxboro	T-U	500.00	230.00	13.80
29	Person 500kV Roxboro	D-U	230.00	24.00	
30	Pine Lake 230kV Raleigh	D-U	230.00	23.00	
31	Pinehurst 115kV Pinehurst	D-U	115.00	24.00	
32	Pisgah Forest (Duke) 230kV Brevard	T-U	115.00	100.00	13.00
33	Pittsboro 230kV Pittsboro	D-U	230.00	23.00	
34	Princeton 115kV Princeton	D-U	115.00	23.00	
35	Raeford 115kV Raeford	D-U	115.00	12.00	
36	Raeford 230kV Raeford	T-U	230.00	115.00	
37	Raeford South 115kV Raeford	D-U	115.00	12.00	
38	Raleigh 115kV Raleigh	D-U	115.00	12.00	
39	Raleigh Atlantic Avenue 115kV Raleigh	D-U	115.00	23.00	
40	Raleigh Blue Ridge 230kV Raleigh	D-U	230.00	23.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Raleigh Brier Creek 230kV Raleigh	D-U	230.00	24.00	
2	Raleigh Durham Airport 230-23kV Raleigh	D-U	230.00	23.00	
3	Raleigh East St. 230kV Raleigh	D-U	230.00	12.00	
4	Raleigh Foxcroft 230kV Raleigh	D-U	230.00	24.00	
5	Raleigh Harrington Street 115kV Raleigh	D-U	115.00	13.20	
6	Raleigh Homestead 230kV Raleigh	D-U	230.00	24.00	
7	Raleigh Honeycutt 230kV Raleigh	D-U	230.00	24.00	
8	Raleigh Leesville Road 230kV Raleigh	D-U	230.00	24.00	
9	Raleigh Northside 115kV Raleigh	D-U	115.00	12.00	
10	Raleigh Oakdale 230kV Raleigh	D-U	230.00	23.00	
11	Raleigh Prison Farm 230kV Raleigh	D-U	230.00	24.00	
12	Raleigh Six Forks 230kV Raleigh	D-U	230.00	24.00	
13	Raleigh South 115kV Raleigh	D-U	115.00	23.00	
14	Raleigh Timberlake 115kV Raleigh	D-U	115.00	23.00	
15	Raleigh Worthdale 230kV Raleigh	D-U	230.00	23.00	
16	Raleigh Yonkers Rd 115kV Raleigh	D-U	115.00	23.00	
17	Ramseur 115kV Ramseur	T-U	115.00	69.00	12.00
18	Ramseur 115kV Ramseur	D-U	115.00	24.00	
19	Red Springs 115kV Red Springs	D-U	115.00	23.00	
20	Reynolds 115kV Asheville	D-U	115.00	12.00	
21	Rhems 230kV New Bern	D-U	230.00	24.00	
22	Rhems 115kV New Bern	D-U	115.00	24.00	
23	Richmond 500kV Rockingham	T-U	500.00	230.00	13.80
24	Richmond County Plant Hamlet	T-A Gen Step-Up	230.00	18.00	13.80
25	Robbins 115kV Robbins	D-U	115.00	24.00	
26	Rockingham 230kV Rockingham	T-U	230.00	115.00	13.80
27	Rockingham 230kV Rockingham	D-U	115.00	23.00	
28	Rockingham Aberdeen Rd. 230kV Rockingham	D-U	230.00	23.00	
29	Rockingham West 115kV Rockingham	D-U	115.00	24.00	
30	Rocky Mount 230kV Rocky Mount	D-U	115.00	24.00	
31	Rocky Mount 230kV Rocky Mount	T-U	230.00	69.00	13.20
32	Rocky Mount 230kV Rocky Mount	T-U	230.00	115.00	13.80
33	Rocky Point 230KV Rocky Point	D-U	230.00	24.00	
34	Rolesville 230kV Rolesville	D-U	230.00	24.00	
35	Rose Hill 230kV Rose Hill	D-U	230.00	24.00	
36	Roseboro 115kV Roseboro	D-U	115.00	23.00	
37	Rowland 230kV Rowland	D-U	230.00	24.00	
38	Rosewood 115KV Goldsboro	D-U	115.00	24.00	
39	Roxboro 115kV Roxboro	D-U	115.00	24.00	
40	Roxboro 115kV Roxboro	T-U	115.00	24.00	

SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Roxboro Bowmantown Rd. 230kV Roxboro	D-U	230.00	23.00	
2	Roxboro South 230kV Roxboro	D-U	230.00	24.00	
3	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 1	230.00	22.00	
4	Roxboro S.E. Plant Roxboro	TA Gen St-Dwn ICTG	138.00	4.00	
5	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 4	230.00	23.50	
6	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 3	230.00	23.50	
7	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 2	230.00	23.50	
8	Roxboro S.E. Plant (Cooling Tower) Roxboro	T-A	230.00	4.00	
9	RTP 230KV Morrisville	D-U	230.00	24.00	
10	Samaria 115kV Samaria	D-U	115.00	24.00	
11	Sanford Deep River 230kV Sanford	D-U	230.00	24.00	
12	Sanford Garden St. 230kV Sanford	D-U	230.00	23.00	
13	Sanford Horner Blvd 230kV Sanford	D-U	230.00	24.00	
14	Sanford US #1 230-23kV Sanford	D-U	230.00	24.00	
15	Scotts Hill 230kV Scotts Hill	D-U	230.00	24.00	
16	Seagrove 115kV Seagrove	D-U	115.00	12.00	
17	Selma 230kV Selma	D-U	115.00	12.00	
18	Selma 230kV Selma	D-U	115.00	24.00	13.20
19	Selma 230kV Selma	T-U	230.00	115.00	
20	Seymour Johnson 115kV Goldsboro	D-U	115.00	12.00	
21	Shannon 115kV Shannon	D-U	115.00	23.00	
22	Shearon Harris S.E. Plant New Hill	T-A Gen Step-Up	230.00	21.50	
23	Siler City 115kV Siler City	D-U	115.00	24.00	
24	Siler City 230kV Siler City	T-U	230.00	115.00	13.80
25	Siler City Hwy 64E 230kV Siler City	D-U	230.00	24.00	
26	Skyland 115-23kV Skyland	D-U	115.00	24.00	
27	Smithfield 115kV Smithfield	D-U	115.00	12.00	
28	Snow Hill 115kV Snow Hill	D-U	115.00	23.00	
29	Southern Pines 115kV Southern Pines	D-U	115.00	23.00	
30	Southport 230kV Southport	D-U	230.00	23.00	
31	So. Pines Center Pk. 115kV Southern Pines	D-U	115.00	23.00	
32	Spring Hope 115kV Spring Hope	D-U	115.00	23.00	
33	Spring Lake 115kV Spring Lake	D-U	230.00	24.00	
34	Spruce Pine 115kV Spruce Pine	D-U	115.00	23.00	
35	Stallings Crossroads 115kV Stallings X-Road	D-U	115.00	23.00	
36	St. Pauls 115kV St. Pauls	D-U	115.00	23.00	
37	Sutton CC Plant Wilmington	T-A Gen St-Up SCC01A	115.00	16.50	
38	Sutton S.E. Plant Wilmington	TAGenSt-Up 2A,2B	115.00	13.20	
39	Sutton S.E. Plant Wilmington	TA Gen Step-Up ICTG1	115.00	13.80	
40	Suton CC Plant Wilmington	TA G St-Up STI SCC01	230.00	23.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Swannanoa 115kV Swannanoa	D-U	115.00	12.00	
2	Swansboro 230kV Swansboro	D-U	230.00	23.00	
3	Tillery H.E. Plant Mt. Gilead	T-A Gen Step-Up	115.00	13.20	
4	Topsail 230kV Hampstead	D-U	230.00	23.00	
5	Troy 115kV Troy	D-U	115.00	12.00	
6	Troy Burnette St 115kV Troy	D-U	115.00	12.00	
7	Vander 115kV Vander	T-U	115.00	24.00	
8	Vanderbilt 115kV Asheville	D-U	115.00	12.00	
9	Vander Dak 115kV	D-U	115.00	12.00	
10	Vander Dak/DuPont/Praxair	D-U	115.00	12.00	
11	VIsta 115kV	D-U	115.00	24.00	
12	Wadesboro 230V Wadesboro	D-U	230.00	24.00	
13	Wadesboro-Bowman Sch 230kV Wadesboro	D-U	230.00	24.00	
14	Wake 500kV Knigthdale	T-U	500.00	230.00	13.80
15	Wake Forest 115kV Wake Forest	T-U	115.00	69.00	13.20
16	Wake Tech 230kV Raleigh	D-U	230.00	24.00	
17	Wallace 115kV Wallace	T-U	115.00	69.00	13.20
18	Wallace 115kV Wallace	D-U	115.00	24.00	
19	Wallace 230kV Wallace	T-U	230.00	115.00	13.80
20	Walters H.E.P. Waterville	T-A	161.00	115.00	13.80
21	Walters H.E.P. Waterville	D-A	115.00	12.00	
22	Walters H.E.P. Waterville	T-A Gen Step-Up	115.00	12.00	
23	Walters H.E.P. Waterville	T-A	138.00	115.00	8.60
24	Warrenton 115kV Warrenton	D-U	115.00	24.00	
25	Warsaw 230kV Warsaw	D-U	230.00	24.00	
26	Wayne County Plant	T-A	230.00	18.00	
27	Waynesville 115kV Waynesville	D-U	115.00	12.00	
28	Weatherspoon 230kV Lumberton	D-U	230.00	24.00	
29	Weatherspoon Plant Lumberton	T-A	230.00	115.00	
30	Weatherspoon Plant Lumberton	T-A Gen Step-Up	115.00	13.20	
31	Weaverville 115kV Weaverville	D-U	115.00	12.00	
32	Wendell 230kV Wendell	D-U	230.00	23.00	
33	West Asheville 115kV Asheville	D-U	115.00	12.00	
34	West End 230kV West End	D-U	230.00	24.00	
35	West End 230kV West End	T-U	230.00	115.00	13.80
36	Whiteville 115kV Whiteville	D-U	115.00	23.00	
37	Whiteville 230kV Whiteville	T-U	230.00	115.00	13.80
38	Whiteville SE Regional Park 115kV Whiteville	D-U	115.00	24.00	
39	Wilmington Cedar Ave. 230kV Wilmington	D-U	230.00	23.00	
40	Wilmington East 230kV Wilmington	D-U	230.00	24.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Wilminton Invista 230 kV Wilmington	D-U	230.00	12.00	
2	Wilmington Ogden 230kV Wilmington	D-U	230.00	23.00	
3	Wilm. 9th & Orange 230kV Wilmington	D-U	230.00	24.00	
4	Wilmington River Road 115KV Wilmington	D-U	115.00	24.00	
5	Wilm. Sunset Pk. 115kV Wilmington	D-U	115.00	24.00	
6	Wilm. Winter Pk. 230kV Wilmington	D-U	230.00	23.00	
7	Wilson 230kV Wilson	T-U	230.00	115.00	13.80
8	Wilson's Mills 230kV Wilson's Mills	D-U	230.00	24.00	
9	Wommack 230kV Kinston	T-U	230.00	115.00	13.80
10	Wrightsville Beach 230kV Wrightsville Beach	D-U	230.00	24.00	
11	Yanceyville 230kV Yanceyville	D-U	230.00	12.00	
12	Youngsville 115kV Youngsville	D-U	115.00	24.00	
13	Zebulon 115kV Zebulon	T-U	115.00	69.00	
14	Zebulon 115kV Zebulon	D-U	115.00	24.00	
15	Zebulon 230kV Zebulon	T-U	230.00	115.00	
16	Zebulon 230kV Zebulon	T-U	115.00	69.00	
17					
18					
19	South Carolina Substations				
20	----------------------				
21	Andrews 115kV Andrews	D-U	115.00	24.00	
22	Bennettsville 230kV Bennettsville	D-U	230.00	24.00	
23	Bethune 115kV Bethune	D-U	115.00	12.00	
24	Bishopville 230kV Bishopville	D-U	230.00	24.00	
25	Camden 230kV Camden	D-U	230.00	24.00	
26	Camden 230kV Camden	T-U	230.00	115.00	
27	Camden Steeplechase 115kV Camden	D-U	115.00	24.00	
28	Cheraw 115kV Cheraw	D-U	115.00	24.00	
29	Cheraw Cash Road 230kV Cheraw	D-U	230.00	23.00	
30	Cheraw-Reid Park 230kV Cheraw	D-U	230.00	24.00	
31	Chesterfield 115kV Chesterfield	D-U	115.00	24.00	
32	Darlington 115kV Darlington	D-U	115.00	24.00	
33	Darlington I.C. Plant Darlington	T-A Gen Step-Up	230.00	14.00	
34	Darlington Pineville Rd 115kV Darlington	D-U	115.00	24.00	
35	Dillon 115kV Dillon	D-U	115.00	24.00	
36	Dillon-Maple 230kV Dillon	D-U	230.00	24.00	
37	Dillon North 230kV Dillon	D-U	230.00	24.00	
38	Elgin 115kV Elgin	D-U	115.00	24.00	
39	Elliott 230kV Elliott	D-U	230.00	24.00	
40	Florence 230kV Florence	D-U	115.00	24.00	

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	04/12/2018	End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Florence 230kV Florence	T-U	230.00	115.00	
2	Florence Burchs Crossroads 115kV Florence	D-U	115.00	23.00	
3	Florence Cashua 230kV Florence	D-U	230.00	23.00	
4	Florence-Ebenezer 230kV Florence	D-U	230.00	24.00	
5	Florence-Mars Bluff 115kV Florence	D-U	115.00	24.00	
6	Florence-Mount Hope 115kV Florence	D-U	115.00	23.00	
7	Florence-Sardis 230kV Sardis	D-U	230.00	24.00	
8	Florence South 115kV Florence	D-U	115.00	24.00	
9	Florence West 230kV Florence	D-U	230.00	24.00	
10	Hartsville 115kV Hartsville	D-U	115.00	24.00	
11	Hartsville-Segars Mill 230kV Hartsville	D-U	230.00	24.00	
12	Hartsville Sonoco 115kV Hartsville	D-U	115.00	14.00	
13	Hemingway 115kV Hemingway	D-U	115.00	24.00	
14	Jefferson 115kV Jefferson	D-U	115.00	23.00	
15	Kingstree 230kV Kingstree	T-U	230.00	115.00	13.80
16	Kingstree 230kV Kingstree	D-U	115.00	24.00	
17	Kingstree North 230kV Kingstree	D-U	230.00	24.00	
18	Lake City 230kV Lake City	D-U	230.00	24.00	
19	Manning 115kV Manning	D-U	115.00	24.00	
20	Marion 230kV Marion	D-U	115.00	24.00	12.00
21	Marion 230kV Marion	T-U	230.00	115.00	13.80
22	Marion-Bypass 115kV Marion	D-U	115.00	23.00	
23	McColl 230kV McColl	D-U	230.00	24.00	
24	Mullins 115kV Mullins	D-U	115.00	24.00	
25	Nichols 115kV Nichols	D-U	115.00	24.00	
26	Olanta 230kV Olanta	D-U	230.00	24.00	
27	Pageland 115kV Pageland	D-U	115.00	24.00	
28	Pamplico 115kV Pamplico	D-U	115.00	24.00	
29	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	21.50	
30	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	115.00	13.80
31	Shaw Field 115kV Sumter	D-U	115.00	12.00	
32	Society Hill 230kV Society Hill	D-U	230.00	24.00	
33	Summerton 230kV Summerton	D-U	230.00	24.00	
34	Sumter 230kV Sumter	D-U	115.00	23.00	
35	Sumter 230kV Sumter	T-U	230.00	115.00	13.80
36	Sumter Alice Drive 230kV Sumter	D-U	230.00	23.00	
37	Sumter Industrial 115-23kV Sumter	D-U	115.00	23.00	
38	Sumter North 230kV Sumter	D-U	230.00	24.00	
39	Sumter-Wedgefield Rd. 230kV Sumter	D-U	230.00	24.00	
40	Wateree HE.P. (Duke) Sumter	T-A	115.00	100.00	7.00

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	04/12/2018	End of 2017/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2					
3					
4		Total T-A			
5		Total T-U			
6		Total D-A			
7		Total D-U			
8					
9					
10					
11					
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40					

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	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
						2
50	2					3
80	2					4
40	1					5
13	1					6
100	4					7
80	2					8
40	1					9
600	2					10
40	1					11
20	3	1				12
50	2					13
50	2					14
25	1					15
25	1		Mb. Sp.(115/23/12kV)	2	25	16
25	1					17
600	2					18
210	1					19
210	1	1				20
420	2					21
25	1					22
40	1					23
25	1					24
25	1					25
25	1					26
25	1					27
350	2					28
19	3	1				29
25	1	2				30
40	1					31
25	4					32
25	1	1				33
25	1					34
50	2					35
50	2	1	Step Down 23/12kV	3	13	36
25	1					37
55	1					38
25	1		Mb.Sp.(115/23/12kV)	2	33	39
300	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
19	3	1				1
19	3					2
74	1					3
30	1					4
19	3					5
2420	8	1				6
25	1					7
25	1					8
10	3					9
50	2					10
40	1					11
25	1					12
25	1					13
300	3	1				14
80	2					15
650	2					16
63	3					17
50	2					18
25	1					19
50	2					20
90	3					21
90	3					22
50	2					23
40	1					24
50	2					25
25	1					26
100	6					27
500	2					28
25	1					29
19	3					30
50	2					31
25	3	1				32
100	5	1				33
50	2					34
25	1					35
90	3					36
80	2					37
50	2					38
200	1					39
50	3	1				40

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	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	2					1
300	1					2
600	2					3
1000	3	1				4
25	1					5
500	2					6
40	1					7
40	1					8
50	2					9
1125	3	1				10
50	3	1				11
80	2					12
25	1					13
50	2					14
25	1					15
13	2					16
25	1					17
300	1					18
25	1					19
300	2					20
15	3	1				21
25	1					22
25	1					23
7	1					24
40	1					25
30	1					26
40	1					27
600	2					28
25	1					29
25	3	1				30
600	2					31
25	1					32
200	1					33
65	2	1				34
50	2					35
25	1					36
50	2					37
25	1					38
600	2					39
25	1					40

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	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1					1
25	1					2
50	2					3
50	2					4
15	3	1				5
50	2					6
40	1					7
90	3					8
40	1					9
40	1					10
13	3					11
23	1					12
50	2					13
25	1					14
40	1					15
25	1					16
25	1					17
40	1					18
25	1					19
65	2					20
50	2					21
400	2					22
65	2					23
600	2					24
50	2					25
50	3					26
50	2					27
9	1					28
80	2					29
40	1					30
25	1					31
25	1	1				32
600	2					33
40	1					34
50	3	1				35
50	2					36
25	1					37
75	3					38
6	3	2				39
50	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
100	4					1
300	1					2
25	1					3
50	3	1				4
19	3					5
25	1					6
65	2					7
25	1					8
50	2					9
40	1					10
50	2					11
400	2					12
50	2					13
50	2					14
						15
600	2					16
13	3					17
90	3					18
50	2					19
25	1					20
50	2					21
25	1					22
50	2					23
25	1					24
31	3	1				25
25	1					26
40	1					27
6	1					28
6	1					29
75	3					30
25	1					31
25	1					32
765	3	1				33
50	2					34
600	2					35
13	1	1				36
50	3	1				37
600	2					38
50	2					39
80	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
50	2					1
50	2					2
25	1					3
300	1					4
50	2					5
19	3					6
25	1					7
25	1					8
200	1					9
25	1					10
40	1					11
75		1				12
50	3	1				13
50	2					14
400	2					15
25	1					16
50	2					17
25	1					18
50	3	1				19
30	1					20
25	1					21
25	1					22
50	2			3	1	23
50	3	1				24
50	2					25
50	2					26
40	1					27
1000	3	1				28
25	1					29
50	2	1				30
80	2					31
100	1					32
25	1					33
40	1					34
55	2					35
400	2	1				36
15	3					37
50	2					38
25	1					39
50	2					40

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
80	2					1
50	2					2
80	2					3
40	1					4
60	2					5
80	2					6
40	1					7
90	3					8
50	2					9
50	2					10
50	2					11
50	2					12
50	2					13
50	2					14
50	2					15
40	1					16
53	3	2		1	2	17
40	1					18
25	1					19
30	1					20
40	1					21
40	1					22
1500	6	1				23
2765	8					24
25	1					25
550	2		230kV Phase Angle	2	1,080	26
50	3	1				27
25	1					28
75	4	1				29
25	1					30
300	2					31
400	2					32
25	1					33
80	2					34
25	1					35
25	1					36
13	1					37
40	1					38
50	3	1				39
60	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
50	2					2
414	3					3
60	1					4
795	3					5
795	3					6
675	3	1				7
40	2	1				8
40	1					9
40	1					10
65	2					11
50	2					12
50	2					13
50	2		23/12Kv Step-Down	4	5	14
65	2					15
13	1					16
19	3	1				17
50	2					18
200	1					19
31	3	1				20
25	1					21
1008	3					22
50	3	1				23
200	1					24
25	1					25
50	2					26
50	3	1				27
25	1					28
50	2					29
50	2					30
50	2					31
25	1					32
40	1					33
50	3	1				34
25	1					35
25	1					36
290	1					37
80	2					38
20	1					39
740	2					40

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	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
50	4	1				1
50	2					2
110	4					3
40	1					4
25	2					5
30	1					6
25	1					7
50	2					8
50	2					9
48	2					10
40	1					11
50	2					12
25	1					13
2000	6	1	MbSp230-115/24/13/12	4	83	14
50	3	2				15
40	1					16
80	3	1				17
50	2	1				18
150	1					19
336	1					20
5	3					21
150	3	1				22
100	1					23
50	2					24
50	2					25
1186	7					26
20	3	1				27
50	2					28
400	2					29
180	2					30
30	1					31
50	2					32
50	3	1				33
50	2					34
600	2		Mb.Sp.(230/23kV)	1	25	35
50	3	1				36
300	1					37
25	1					38
50	2					39
50	2					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

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50	2					1
100	4					2
50	2					3
40	1					4
50	3	3				5
90	3					6
600	2					7
40	1					8
400	2					9
100	4					10
25	1					11
40	1					12
50	3	1				13
50	2					14
300	1					15
50	1	1				16
						17
						18
						19
						20
25	1					21
50	2					22
25	1					23
50	2					24
25	1					25
200	1					26
25	1					27
25	1					28
25	1					29
50	2					30
25	1					31
50	3	1				32
1084	8					33
40	1					34
50	3	1				35
25	1					36
25	1					37
9	1	1				38
25	1					39
75	3					40

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	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
600	2					1
40	1	1				2
25	1					3
25	1					4
25	1					5
50	2					6
40	1					7
50	3	1				8
50	2					9
50	3	1				10
50	2					11
50	2					12
20	3					13
6	1					14
150	1					15
25	1					16
65	2					17
30	3	1				18
25	1					19
25	1					20
400	2					21
50	3	1				22
25	1					23
50	2					24
15	3					25
25	1					26
25	1					27
25	1					28
990	3	1				29
600	2					30
50	3	1	12/23kV Step-Up	1	25	31
25	1					32
25	1					33
75	3					34
600	2					35
25	1					36
50	3	1				37
50	2					38
50	2					39
154	2					40

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	04/12/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
						2
						3
18351						4
24832						5
5						6
13954						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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	04/12/2018	End of 2017/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Customer and Market Services Provided by Affiliate	Duke Energy Carolinas	various	42,602,671
3		Duke Energy Florida	various	1,194,507
4	Generation Services Provided by Affiliate	Duke Energy Carolinas	various	377,790,268
5		Duke Energy Florida	various	407,298
6		Duke Energy Indiana	various	409,080
7	Other Goods and Services Provided by Affiliate	Duke Energy Carolinas	various	35,774,917
8		Piedmont Natural Gas	various	76,729,026
9	Transmission and Distribution Services Provided	Duke Energy Carolinas	various	22,485,860
10	by Affiliate	Duke Energy Florida	various	2,099,643
11				
12				
13	Service Company Transactions	Duke Energy Business Services	various	502,422,246
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	DE Progress Provided Customer and Market Services	Duke Energy Carolinas	various	3,658,074
22		Duke Energy Florida	various	2,462,235
23		Duke Energy Ohio	various	823,907
24		Duke Energy Indiana	various	709,571
25		Duke Energy Kentucky	various	299,400
26		Piedmont Natural Gas	various	330,119
27	DE Progress Provided Generation Services	Duke Energy Carolinas	various	32,702,337
28		Duke Energy Florida	various	2,625,489
29		Duke Energy Indiana	various	1,052,058
30		Duke Energy Kentucky	various	317,354
31	DE Progress Provided Other Goods and Services	Duke Energy Carolinas	various	3,381,801
32		Duke Energy Florida	various	1,496,630
33		Duke Energy Indiana	various	821,395
34	DE Progress Provided Transmission and	Duke Energy Carolinas	various	21,237,560
35	Distribution Services	Duke Energy Florida	various	10,575,071
36		Duke Energy Indiana	various	2,023,482
37		Duke Energy Kentucky	various	262,275
38		Duke Energy Ohio	various	1,358,820
39	DE Progress Provided Service Company Transactions	Duke Energy Business Services	various	2,993,286
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: a

Transactions on this page do not include transactions between Duke Energy Progress and Duke Energy Progress Receivables.

Schedule Page: 429 Line No.: 13 Column: a

When an employee of the Service Company performs services for a Client Company, costs will be directly assigned or distributed or allocated. For allocated services, the allocation method will be on a basis reasonably related to the service performed. The Service Company Utility Service Agreement prescribes 23 Service Company functions and approximately 20 allocation methods.

Functions and Allocation Methods:

Information Systems
- Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second
- Number of Personal Computer Workstations Ratio
- Number of Information Systems Servers Ratio
- Number of Employees Ratio

Meters
- Number of Customers Ratio

Transportation
- Number of Employees Ratio
- Three Factor Formula

Electric System Maintenance
- Circuit Miles of Electric Transmission Lines Ratio
- Circuit Miles of Electric Distribution Lines Ratio

Marketing and Customer Relations and Grid Solutions
- Number of Customers Ratio

Electric Transmission & Distribution Engineering & Construction
- Electric Transmission Plant's Construction - Expenditures Ratio
- Electric Distribution Plant's Construction - Expenditures Ratio

Power Engineering & Construction
- Electric Production Plant's Construction - Expenditures Ratio

Human Resources
- Number of Employees Ratio

Supply Chain
- Procurement Spending Ratio
- Inventory Ratio

Facilities
- Square Footage Ratio

Accounting
- Three Factor Formula
- Generating Unit MW Capability Ratio

Power Planning and Operations
- Electric Peak Load Ratio
- Weighted Avg of the Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio
- Sales Ratio
- Weighted Avg of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio
- Generating Unit MW Capability Ratio

Public Affairs
- Three Factor Formula
- Weighted Avg of Number of Customers Ratio and Number of Employees Ratio

Legal
- Three Factor Formula

Rates
- Sales Ratio

Finance

- Three Factor Formula

Rights of Way
- Circuit Miles of Electric Transmission Lines Ratio
- Circuit Miles of Electric Distribution Lines Ratio
- Electric Peak Load Ratio

Internal Auditing
- Three Factor Formula

Environmental, Health and Safety
- Three Factor Formula
- Sales Ratio

Fuels
- Sales Ratio

Investor Relations
- Three Factor Formula

Planning
- Three Factor Formula

Executive
- Three Factor Formula

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