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** 2016/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 1,144 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 150 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 2016/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* (704) 382-1061	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/13/2017

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 William E. Currens, Jr. 02 Title SVP, Chief Accounting Off & Contr	03 Signature William E. Currens, Jr.	04 Date Signed *(Mo, Da, Yr)* 04/13/2017

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/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".

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	04/13/2017	End of 2016/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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	N/A

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	04/13/2017	End of 2016/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 coverted 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	04/13/2017	End of 2016/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	04/13/2017	End of 2016/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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Schedule Page: 103 Line No.: 1 Column: d

The remaining 1.0% is owned by CaroFund, Inc.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	1,300,000
2			
3	Executive Vice President, effective 5/16/16	Dhiaa M. Jamil	750,000
4	Chief Operating Officer, effective 5/1/16		
5	Executive Vice President, resigned 5/1/16		
6	President, Generation and Transmission,		
7	resigned 5/1/16		
8			
9	Executive Vice President	Julia S. Janson	525,000
10	Chief Legal Officer		
11	Secretary		
12			
13	Executive Vice President, Strategic Services	A.R. Mullinax	150,000
14	Retired 5/1/16		
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	666,750
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			
27	President, North Carolina	David B. Fountain	369,900
28			
29			
30	Executive Vice President	Steven K. Young	630,000
31	Chief Financial Officer		
32			
33	Treasurer and Senior Vice President, Tax effective 2/1/6	Stephen Gerard De May	358,143
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.	270,000
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	463,500
43	Administration and Chief Human Resources Officer,		
44	effective 5/1/16		

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	500,000
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	113,077
20	Effective 10/01/16		
21			
22	President, Commercial Portfolio	Greg Wolf	192,070
23	resigned 7/7/16		
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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	04/13/2017	End of 2016/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	
3	Energy Solutions and President, Midwest and Florida Regions	
4		
5		
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, Chief Legal Officer	
15	Secretary	
16		
17	Lloyd M. Yates	550 South Tryon Street, Charlotte, NC 28202
18	Executive Vice President,	
19	Customer and Delivery Operations and President	
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	04/13/2017	End of 2016/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 Agreement	ER12-1343
2	RS 172	ER16-2729
3	RS 180	ER16-2729
4	RS 182	ER16-2729
5	RS 184	ER16-2729
6	RS 195	ER16-2729
7	RS 197	ER16-2729
8	RS 200	ER16-2729
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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) 04/13/2017	Year/Period of Report End of 2016/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	201605165179	05/16/2016	ER09-1165	Annual Transmission Update	Joint Open Access Transmission Tariff
2					
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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	04/13/2017	End of 2016/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
1	111	Prepayments	(c)	57
2	112	Accum. Prov. for Pensions & Benefits	(c)	29
3	117	Other Long Term Interest Expense	(c)	62-67
4	200	Intangible Amortization Reserve	(c)	21
5	205	Intangible Plant	(g)	5
6	205	Production Plant	(g)	46
7	207	Transmission Plant	(g)	58
8	207	Distribution Plant	(g)	75
9	207	General Plant	(g)	98-99
10	219	Transmission Depr. Reserve	(c)	25
11	219	Distribution Depr. Reserve	(c)	26
12	219	General Depr. Reserve	(c)	28
13	232	SFAS 158 Regulatory Assets	(f)	3
14	263	Other Taxes - FICA/Unemployment / Social Security	(i)	3 & 5
15	263	Other Taxes - Real & Personal Property	(i)	10 & 21
16	321	Total Production Expense	(b)	80
17	321	Total Transmission Expense	(b)	112
18	323	Total Admin & General Expenses	(b)	197
19	327	Purchase Power Demand Charges	(j)	Total
20	335	Industry Dues, R&D,C-V Nuc Pwr Assoc	(b)	1-3
21	336	Intangible Amortization	(f)	1
22	336	Production Depreciation Expense	(b)	2-6
23	336	Transmission Depreciation Expense	(b)	7
24	336	General Depr. Expense	(b)	10
25	354	A&G Labor	(b)	27
26	354	Total Direct Payroll - O&M Labor	(b)	28
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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	04/13/2017	End of 2016/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. During the first quarter of 2016, Duke Energy Progress entered into a 60 year franchise agreement with Grimesland, NC in Pitt County.

During the second quarter, Duke Energy Progress had two franchise agreements to expire. Those franchise agreements were for Nash (Town of Sharpsburg)and Forsyth Counties.

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 first quarter of 2016, Duke Energy Progress had a 2.76% pay increase for non-craft employees.

During the third quarter of 2016, Duke Energy Progress granted a 3% general wage increase for non-represented craft employees totaling $4,305,499 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 2016.

The officer and director appointments and resignations that occurred during 2016 are as follows:

APPOINTMENTS

Effective January 2016

John Elnitsky	Senior Vice President, Nuclear Engineering
Jeffrey M. Stone	Vice President, Corporate Audit Services
John L. Sullivan III	Assistant Treasurer
Sandra S. Wyckoff	Vice President, Ethics and Compliance and Chief Ethics Officer

Effective February 2016

Keith Gerard Butler	Senior Vice President, Global Risk Management and Insurance,and Chief Risk Officer
Stephen Gerard De May	Treasurer and Senior Vice President, Tax

RESIGNATIONS

Effective January 2016

John Elnitsky	Senior Vice President, Ash Basin Strategy
Jeffrey M. Stone	Vice President Internal Audit, Ethics and Compliance
Sandra S. Wyckoff	Assistant Treasurer

Effective February 2016

Keith Gerard Butler	Senior Vice President, Tax
Stephen Gerard De May	Senior Vice President
Dwight L. Jacobs	Senior Vice President, Global Risk Management and Insurance and Chief Risk Officer
Jennifer L. Weber	Executive Vice President, External Affairs and Strategic Policy

Effective March 2016

Charles M. Gates	Senior Vice President, Chief Fossil/Hydro Officer

APPOINTMENTS

Effective April 2016

Paul Draovitch	Senior Vice President, Fossil Hydro Operations
Terrell N. Garren	Vice President and Chief Security Officer
George T. Hamrick	Senior Vice President, Coal Combustion Products
Regis T. Repko	Senior Vice President and Chief Fossil/Hydro Officer
Sandra S. Wyckoff	Vice President and Chief Ethics and Compliance Officer
Thomas Cooper Monroe III	Director, State Tax

Effective May 2016

Melissa H. Anderson	Executive Vice President, Administration and Chief Human Resources Officer
William E. Currens Jr.	Senior Vice President, Chief Accounting Officer and Controller
David L. Doss Jr.	Vice President, Accounting
Dhiaa M. Jamil	Executive Vice President and Chief Operating Officer
Brian D. Savoy	Senior Vice President, Business Transformation and Technology

Effective June 2016

Caren B. Anders	Vice President, Operations Support
Richard W. Bagley	Vice President, Transmission Engineering, Resource and Project Management
Stephen J. Immel	Vice President, Carolinas Coal Generation
V. Nelson Peeler	Vice President, Transmission Systems Planning and Operations
Tom Silinski	Vice President, Total Rewards and Human Resource Operations
Julie K. Turner	Vice President, Carolinas Natural Gas Generation

RESIGNATIONS

Effective April 2016

Paul Draovitch	Vice President, Fossil Hydro Operations, Carolinas East
George T. Hamrick	Vice President, Coal Combustion Products
Regis T. Repko	Senior Vice President, Nuclear Corporate
Sandra S. Wyckoff	Vice President, Ethics and Compliance and Chief Ethics Officer

Effective May 2016

Melissa H. Anderson	Senior Vice President and Chief Human Resources Officer
W. Bryan Buckler	Vice President, Accounting
Dhiaa M. Jamil	President, Generation and Transmission and Executive Vice President
A. R. Mullinax	Executive Vice President, Strategic Services

Brian D. Savoy	Senior Vice President and Chief Accounting Officer and Controller

Effective June 2016

Jason M. Allen	Vice President, Carolinas West
Caren B. Anders	Vice President, Delivery Operations Support
Richard W. Bagley	Vice President, Transmission Engineering
Stephen J. Immel	Vice President, Outage and Project Services
V. Nelson Peeler	Vice President, Transmission Systems Operations
Tom Silinksi	Vice President, Human Resources Operations

APPOINTMENTS

Effective July 2016

Robert F. Caldwell	President, Duke Energy Renewables and Distributed Energy Technology

Effective September 2016

Scott L. Batson	Senior Vice President, Nuclear Operations (SC)
Robert J. Duncan II	Senior Vice President, Nuclear Operations (NC)
Douglas F Esamann	Executive Vice President, Energy Solution and President,Midwest and Florida Regions
T. Preston Gillespie Jr.	Senior Vice President and Nuclear Chief Operating Officer
Kelvin Henderson	Senior Vice President, Nuclear Corporate
Michael A. Lewis	Senior Vice President and Chief Distribution Officer
John F. Smith III	Senior Vice President, Carolinas Distribution Operations
Lloyd M. Yates	Executive Vice President, Customer and Delivery Operations and President, Carolinas Region

RESIGNATIONS

Effective July 2016

Robert F. Caldwell	Senior Vice President, Distributed Energy Resources

Effective August 2016

Heath J. Shuler	Senior Vice President, Federal Governmental Affairs

Effective September 2016

Douglas F Esamann	Executive Vice President and President, Midwest and Florida Regions
T. Preston Gillespie Jr.	Senior Vice President, Nuclear Operations
Michael A. Lewis	Senior Vice President and Chief Transmission Officer
John F. Smith III	Senior Vice President, Carolinas Delivery Operations
Lloyd Yates	Executive Vice President, Market Solutions and President, Carolinas Region

APPOINTMENTS

Effective October 2016

Sam Holeman	Vice President, Transmission Systems Planning and Operations
Nelson Peeler	Senior Vice President and Chief Transmission Officer

Effective November 2016

Tanya Hamilton	Site Vice President, Harris
Benjamin Waldrep	Vice President, Operational Excellence

RESIGNATIONS

Effective October 2016

John Elnitsky	Senior Vice President, Nuclear Engineering
Nelson Peeler	Vice President, Transmission Systems Planning and

Operations

Effective November 2016

Benjamin Waldrep — Site Vice President, Harris

14. Not applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) ☒ An Original (2) ☐ A Resubmission	04/13/2017	End of 2016/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	26,516,624,323	25,650,168,278
3	Construction Work in Progress (107)	200-201	1,303,611,534	1,108,311,519
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		27,820,235,857	26,758,479,797
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	11,379,160,840	10,941,910,151
6	Net Utility Plant (Enter Total of line 4 less 5)		16,441,075,017	15,816,569,646
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	311,017,469	337,766,031
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		62,792,088	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		836,611,115	822,011,827
10	Spent Nuclear Fuel (120.4)		269,992,039	206,799,870
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	730,006,410	644,547,755
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		750,406,301	722,029,973
14	Net Utility Plant (Enter Total of lines 6 and 13)		17,191,481,318	16,538,599,619
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		35,107,688	33,932,904
19	(Less) Accum. Prov. for Depr. and Amort. (122)		9,888,862	9,362,277
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	18,169,203	17,568,887
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)		41,410,010	41,395,996
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,473,469,794	2,298,518,992
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)		8,897,044	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,567,164,877	2,382,054,502
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,348,376	13,554,701
36	Special Deposits (132-134)		0	514,971
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		330,199,653	308,854,167
41	Other Accounts Receivable (143)		5,234,476	73,989,677
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,968,264	6,099,951
43	Notes Receivable from Associated Companies (145)		164,938,000	0
44	Accounts Receivable from Assoc. Companies (146)		74,661,835	132,529,770
45	Fuel Stock (151)	227	262,286,714	312,175,426
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	780,734,297	739,816,167
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	163,973	91,590
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	86,749,196	82,444,163

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	04/13/2017	End of 2016/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	32,787,942	36,190,599
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)		44,574,206	39,015,713
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		131,731	151,210
61	Accrued Utility Revenues (173)		125,363,222	103,763,934
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		723,557	841,823
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		44,131,820	844,835
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		8,897,044	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,948,163,690	1,838,678,795
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		39,797,537	39,748,188
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	166,620,786	131,936,167
72	Other Regulatory Assets (182.3)	232	3,099,341,503	2,804,070,065
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,936,284	3,509,698
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)		4,503,190	-455
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	490,376,158	244,979,519
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)		6,643,127	7,716,478
82	Accumulated Deferred Income Taxes (190)	234	2,083,860,008	1,942,751,307
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		5,894,078,593	5,174,710,967
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		27,600,888,478	25,934,043,883

Schedule Page: 110 Line No.: 35 Column: d

Amount has been restated to reflect the reclassification of negative cash balances from Account 131 to Account 232 in order to be consistent with the current year presentation.

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	04/13/2017	end of 2016/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	4,860,407,802	4,561,423,673
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-286,334,903	-286,751,535
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)	-206,646	-232,257
16	Total Proprietary Capital (lines 2 through 15)		7,358,242,824	7,058,816,452
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,473,485,000	6,023,485,000
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	253,793,610
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		16,440,408	16,245,840
24	Total Long-Term Debt (lines 18 through 23)		6,907,044,592	6,411,032,770
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		139,410,389	141,917,584
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		8,664,132	5,954,466
29	Accumulated Provision for Pensions and Benefits (228.3)		232,000,482	240,363,326
30	Accumulated Miscellaneous Operating Provisions (228.4)		21,985,322	23,665,414
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		5,574,632	4,807,558
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		156,050	15,357,740
34	Asset Retirement Obligations (230)		4,507,556,500	4,567,093,298
35	Total Other Noncurrent Liabilities (lines 26 through 34)		4,915,347,507	4,999,159,386
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		592,188,925	393,902,836
39	Notes Payable to Associated Companies (233)		0	209,278,000
40	Accounts Payable to Associated Companies (234)		220,219,478	201,036,264
41	Customer Deposits (235)		141,048,805	146,157,468
42	Taxes Accrued (236)	262-263	107,826,421	18,130,917
43	Interest Accrued (237)		102,928,865	95,980,630
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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)		5,107,439	9,696,116
48	Miscellaneous Current and Accrued Liabilities (242)		386,629,419	169,717,984
49	Obligations Under Capital Leases-Current (243)		2,507,196	2,197,254
50	Derivative Instrument Liabilities (244)		5,574,632	4,807,558
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		5,574,632	4,807,558
52	Derivative Instrument Liabilities - Hedges (245)		156,050	91,316,091
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		156,050	15,357,740
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,558,456,548	1,322,055,820
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		23,027,797	20,800,811
57	Accumulated Deferred Investment Tax Credits (255)	266-267	146,399,648	131,604,359
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	56,303,593	41,651,820
60	Other Regulatory Liabilities (254)	278	1,228,887,118	978,680,077
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)		3,902,880,700	3,739,969,531
64	Accum. Deferred Income Taxes-Other (283)		1,504,298,151	1,230,272,857
65	Total Deferred Credits (lines 56 through 64)		6,861,797,007	6,142,979,455
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		27,600,888,478	25,934,043,883

Schedule Page: 112   Line No.: 38   Column: d

Amount has been restated to reflect the reclassification of negative cash balances from Account 131 to Account 232 in order to be consistent with the current year presentation.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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	5,265,756,021	5,266,192,917		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,740,384,579	2,932,930,249		
5	Maintenance Expenses (402)	320-323	562,811,662	566,973,061		
6	Depreciation Expense (403)	336-337	604,487,167	573,292,400		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	31,071,436	20,789,048		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	12,758,733	5,316,139		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		30,447,884	30,164,426		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		165,027,228	130,066,214		
13	(Less) Regulatory Credits (407.4)		161,345,859	165,833,131		
14	Taxes Other Than Income Taxes (408.1)	262-263	153,758,259	138,313,094		
15	Income Taxes - Federal (409.1)	262-263	-53,582,117	-41,758,619		
16	- Other (409.1)	262-263	-23,847,119	-2,237,790		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,223,186,084	1,331,405,049		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	840,004,091	994,501,019		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,304,895	-6,690,167		
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)		364,445	375,837		
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)		4,439,484,506	4,517,853,117		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		826,271,515	748,339,800		

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	04/13/2017	End of 2016/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
5,265,756,021	5,266,192,917					2
						3
2,740,384,579	2,932,930,249					4
562,811,662	566,973,061					5
604,487,167	573,292,400					6
						7
31,071,436	20,789,048					8
12,758,733	5,316,139					9
30,447,884	30,164,426					10
						11
165,027,228	130,066,214					12
161,345,859	165,833,131					13
153,758,259	138,313,094					14
-53,582,117	-41,758,619					15
-23,847,119	-2,237,790					16
1,223,186,084	1,331,405,049					17
840,004,091	994,501,019					18
-5,304,895	-6,690,167					19
						20
						21
364,445	375,837					22
						23
						24
4,439,484,506	4,517,853,117					25
826,271,515	748,339,800					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	04/13/2017	End of 2016/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)		826,271,515	748,339,800		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		25,518,661	25,698,650		
34	(Less) Expenses of Nonutility Operations (417.1)		14,426,348	17,191,434		
35	Nonoperating Rental Income (418)		-524,788	-305,192		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	450,644	554,638		
37	Interest and Dividend Income (419)		3,062,143	1,861,330		
38	Allowance for Other Funds Used During Construction (419.1)		49,614,088	47,191,939		
39	Miscellaneous Nonoperating Income (421)		10,386,161	19,096,739		
40	Gain on Disposition of Property (421.1)		1,274,712	1,170,799		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		75,355,273	78,077,469		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		118,435			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		37,429,332	2,593,653		
46	Life Insurance (426.2)		-1,078,345	-430,035		
47	Penalties (426.3)		700,300	90,333		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,526,385	2,545,061		
49	Other Deductions (426.5)		1,811,310	5,690,757		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		41,507,417	10,489,769		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,790,277	2,085,912		
53	Income Taxes-Federal (409.2)	262-263	-4,877,441	1,725,244		
54	Income Taxes-Other (409.2)	262-263	-1,164,465	1,626,643		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	21,619,976	58,188,618		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	15,873,635	54,326,927		
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)		1,494,712	9,299,490		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		32,353,144	58,288,210		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		264,245,568	251,576,189		
63	Amort. of Debt Disc. and Expense (428)		5,159,109	6,022,976		
64	Amortization of Loss on Reaquired Debt (428.1)		1,073,351	1,121,112		
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)		1,889,048	299,640		
68	Other Interest Expense (431)		3,708,098	1,556,765		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		16,851,277	20,432,479		
70	Net Interest Charges (Total of lines 62 thru 69)		259,223,897	240,144,203		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		599,400,762	566,483,807		
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)		599,400,762	566,483,807		

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	04/13/2017	End of 2016/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		4,557,197,977	3,991,747,699
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Transfer to Unappropriated RE (Account 216.1)		34,012	(102,935)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		34,012	(102,935)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		598,950,118	565,929,169
17	Appropriations of Retained Earnings (Acct. 436)			
18	Hydro Project Reserve Amortization	215.1	-494,550	(375,956)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-494,550	(375,956)
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		-300,000,000	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-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)		4,855,687,557	4,557,197,977
	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	04/13/2017	End of 2016/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)		4,720,245	4,225,696
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		4,720,245	4,225,696
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		4,860,407,802	4,561,423,673
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-286,751,535	(287,409,108)
50	Equity in Earnings for Year (Credit) (Account 418.1)		450,644	554,638
51	(Less) Dividends Received (Debit)			
52	Transfer from Unappropriated RE (Account 216.1)		-34,012	102,935
53	Balance-End of Year (Total lines 49 thru 52)		-286,334,903	(286,751,535)

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.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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)	599,400,762	566,483,807
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	604,487,167	573,292,400
5	Amortization and Accretion	304,012,226	258,823,097
6	Net (Increase) Decrease in Mark-to-Market and Hedging Transactions	4,425,410	-3,386,879
7	Contributions to Company-Sponsored Pension Plans	-23,739,545	-42,494,366
8	Deferred Income Taxes (Net)	388,928,334	340,765,721
9	Investment Tax Credit Adjustment (Net)	-5,304,895	-6,690,167
10	Net (Increase) Decrease in Receivables	119,196,972	201,641,683
11	Net (Increase) Decrease in Inventory	12,300,856	-50,031,030
12	Net (Increase) Decrease in Allowances Inventory	-26,396,581	-21,444,279
13	Net Increase (Decrease) in Payables and Accrued Expenses	322,632,164	18,707,717
14	Net (Increase) Decrease in Other Regulatory Assets	35,266,347	80,571,665
15	Net Increase (Decrease) in Other Regulatory Liabilities	26,379,454	23,205,346
16	(Less) Allowance for Other Funds Used During Construction	49,614,088	47,191,939
17	(Less) Undistributed Earnings from Subsidiary Companies	450,644	554,638
18	Other (provide details in footnote):	-352,401,923	-275,764,915
19	Accrued Pension and Other Post-Retirement Benefit Costs Adj to NI	-32,078,748	-14,117,796
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,927,043,268	1,601,815,427
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,469,812,476	-1,262,713,419
27	Gross Additions to Nuclear Fuel	-209,562,613	-355,198,067
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-1,174,784	-106,142
30	(Less) Allowance for Other Funds Used During Construction	49,614,088	47,191,939
31	Other (provide details in footnote):		
32	Additions from Affiliated Companies	-2,623,342	-16,071,435
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,732,787,303	-1,681,281,002
35			
36	Acquisition of Other Noncurrent Assets (d)		-1,194,760,576
37	Proceeds from Disposal of Noncurrent Assets (d)	4,211,328	
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-165,904,339	236,320,349
40	Contributions and Advances from Assoc. and Subsidiary Companies	74,931	1,200,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,657,522,217	-726,916,616
45	Proceeds from Sales of Investment Securities (a)	1,619,065,118	677,156,466

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	04/13/2017	End of 2016/Q4

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		-55,814,527
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		1,947,021
53	Other (provide details in footnote):	22,769,806	-31,543,261
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,910,092,676	-2,773,692,146
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	508,607,709	1,194,926,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Equity Contribution from Parent		625,000,000
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)	508,607,709	1,819,926,000
71	Other Financing Activities (provide details in footnote)	-4,255,524	-9,993,680
72	Payments for Retirement of:		
73	Long-term Debt (b)	-15,746,073	-991,072,645
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	-209,278,000	359,278,000
78	Net Decrease in Short-Term Debt (c)		
79	Dividends to Parent	-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)	-20,671,888	1,178,137,675
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-3,721,296	6,260,956
87			
88	Cash and Cash Equivalents at Beginning of Period	14,069,672	7,808,716
89			
90	Cash and Cash Equivalents at End of period	10,348,376	14,069,672

Schedule Page: 120 Line No.: 13 Column: c

Amount has been restated to reflect the reclassification of negative cash balances from Account 131 to Account 232 in order to be consistent with the current year presentation.

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

Asset retirement obligation liabilities settled	$ (211,819,383)
Change in other noncurrent assets	(146,534,095)
Change in deferred credits and other long-term liabilities	(16,467,814)
Change in prepaid and other current assets	(5,784,574)
Gain on sale of assets	(5,577,429)
Equity method investment income	801,681
Impairment	633,767
Accrued charitable contributions related to	
Piedmont merger commitments	32,345,924
	$(352,401,923)

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

Year to date Cost of Removal Activity	$19,937,173
Death proceeds from COLI and Rabbi Trust	2,832,633
	$22,769,806

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

Primarily unamortized debt expenses associated with issuances of LT Debt $(4,255,524)

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

Significant noncash transactions:

Accrued capital expenditures $146,949,311

Supplemental Disclosures:

Cash paid for interest, net of amount capitalized $248,369,311

Cash refunded for income taxes $286,648,408

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

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

Cash (131) $ 13,554,701

Special deposits (132-134)	514,971
	$ 14,069,672

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

Amount has been restated to reflect the reclassification of negative cash balances from Account 131 to Account 232 in order to be consistent with the current year presentation.

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

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

Cash (131)	$ 10,348,376

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

Amount has been restated to reflect the reclassification of negative cash balances from Account 131 to Account 232 in order to be consistent with the current year presentation.

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 previously required the current portion of deferred income taxes to be reported as a current asset or liability on the balance sheet. An Accounting Standards update now requires that all deferred tax balances be classified as non-current for GAAP purposes, which is consistent with FERC reporting. Duke Energy Corporation adopted this methodology for GAAP purposes effective as of December 31, 2015.
(j) 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.

The Combined Notes To Consolidated Financial Statements below are as published in the fourth quarter ended December 31, 2016 Form 10-K (includes Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Duke Energy Florida, LLC, Duke Energy Ohio, Inc., and Duke Energy Indiana, LLC) filed on February 24, 2017. See "Index to the Combined Notes to Consolidated Financial Statements" for a listing of applicable notes for Duke Energy Progress, LLC.

OTHER DISCLOSURE

Cash payments (receipts) for interest and income taxes for year-to-date fourth quarter 2016 were approximately $248 million and ($287) million, respectively.

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	•		•	•	•	•		•	•	•	•		•	•	•	•	•		•	•	•	•	•	•	•

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, (ii) Piedmont, a subsidiary registrant acquired on October 3, 2016, which is consolidated within Duke Energy but not separately stated in the combined presentation and (iii) other 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); and Duke Energy Indiana, LLC (Duke Energy Indiana). On October 3, 2016, Duke Energy acquired Piedmont Natural Gas Company, Inc. (Piedmont) which also became a wholly owned subsidiary and subsidiary registrant of Duke Energy. Duke Energy's consolidated financial statements include Piedmont's results of operations and cash flow activity subsequent to the acquisition. See Note 2 for additional information regarding the acquisition. 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 (Duke Energy Registrants).

In October 2016, Duke Energy completed the acquisition of Piedmont, an energy services company whose principal business is the distribution of natural gas, for a total cash purchase price of $5.0 billion. The acquisition provides a foundation for establishing a broader strategic natural gas infrastructure platform within Duke Energy to complement the existing natural gas pipeline investments and the natural gas business located in the Midwest. For additional information on the details of this transaction including purchase price allocation and acquisition financing, see Note 2. Piedmont continues to maintain reporting requirements as a Securities and Exchange Commission (SEC) registrant.

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). For additional information on the sale of International Energy see Note 2.

The information in these combined notes relates to each of the Duke Energy Registrants, excluding Piedmont, as noted in the Index to Combined Notes to Consolidated Financial Statements. However, none of the 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.

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. Substantially all of Duke Energy Carolinas' operations qualify for regulatory accounting.

Progress Energy is a public utility holding company headquartered in Raleigh, North Carolina, subject to regulation by the FERC. Progress Energy conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida. Substantially all of Progress Energy's operations qualify for regulatory accounting.

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. Substantially all of Duke Energy Progress' operations qualify for regulatory accounting.

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. Substantially all of Duke Energy Florida's operations qualify for regulatory accounting.

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 also conducts competitive auctions for retail electricity supply in Ohio whereby recovery of the energy price is 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 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 "Acquisitions and Dispositions." 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. Substantially all of Duke Energy Indiana's operations qualify for regulatory accounting. On January 1, 2016, Duke Energy Indiana, an Indiana corporation, converted into an Indiana limited liability company.

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 invested in joint venture businesses including regulated interstate natural gas transportation and storage and intrastate natural gas transportation businesses. Piedmont is subject to the regulatory provisions of the NCUC, PSCSC, Tennessee Regulatory Authority (TRA) and FERC. Substantially all of Piedmont's operations qualify for regulatory accounting.

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, 2016 or 2015.

		December 31,	
(in millions)	**Location**	**2016**	**2015**
Duke Energy			
Accrued compensation	Current Liabilities	**$ 765**	$ 619
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 248**	$ 213
Collateral liabilities	Current Liabilities	**155**	141
Progress Energy			
Income taxes receivable	Current Assets	**$ 19**	$ 129
Customer deposits	Current Liabilities	**363**	373
Derivative liabilities	Current Liabilities	**1**	201
Duke Energy Progress			
Income taxes receivable	Current Assets	**$ 16**	$ 111
Customer deposits	Current Liabilities	**141**	141
Accrued compensation	Current Liabilities	**135**	108
Derivative liabilities	Current Liabilities	**—**	76
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 222**	$ 232
Derivative liabilities	Current Liabilities	**1**	125
Duke Energy Ohio			
Income taxes receivable	Current Assets	**$ 16**	$ 59
Other receivable	Current Assets	**—**	33
Accrued litigation reserve	Current Liabilities	**4**	80
Collateral liabilities	Current Liabilities	**62**	48
Duke Energy Indiana			
Collateral liabilities	Current Liabilities	**$ 44**	$ 44

Discontinued Operations

The results of operations of the International Disposal Group and 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 and assets held for sale (AHFS) and liabilities associated with AHFS as of December 31, 2015. See Note 2 for additional information.

Amounts Attributable to Controlling Interests

Duke Energy's amount of (Loss) Income from Discontinued Operations, net of tax presented on the Consolidated Statements of Operations includes amounts attributable to noncontrolling interest. The following table presents Net Income Attributable to Duke Energy Corporation for continuing operations and discontinued operations.

	Year ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Income from Continuing Operations	**$ 2,578**	$ 2,654	$ 2,538
Income from Continuing Operations Attributable to Noncontrolling Interests	**7**	9	5
Income from Continuing Operations Attributable to Duke Energy Corporation	**$ 2,571**	$ 2,645	$ 2,533
(Loss) Income From Discontinued Operations, net of tax	**$ (408)**	$ 177	$ (649)
Income from Discontinued Operations Attributable to Noncontrolling Interests, net of tax	**11**	6	1
(Loss) Income From Discontinued Operations Attributable to Duke Energy Corporation, net of tax	**$ (419)**	$ 171	$ (650)
Net Income	**$ 2,170**	$ 2,831	$ 1,889
Net Income Attributable to Noncontrolling Interests	**18**	15	6
Net Income Attributable to Duke Energy Corporation	**$ 2,152**	$ 2,816	$ 1,883

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. Other 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 Investments and Other Assets on the Consolidated Balance Sheets. At December 31, 2016 and 2015, Duke Energy had restricted cash totaling $137 million and $98 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. Reserves are established for excess and obsolete inventory. Inventory reserves were not material at December 31, 2016 and 2015. The components of inventory are presented in the tables below.

	December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Materials and supplies	**$ 2,374**	**$ 767**	**$ 1,167**	**$ 813**	**$ 354**	**$ 84**	**$ 312**
Coal	**774**	**251**	**314**	**148**	**166**	**19**	**190**
Natural gas, oil and other	**374**	**37**	**236**	**115**	**121**	**34**	**2**
Total inventory	**$ 3,522**	**$ 1,055**	**$ 1,717**	**$ 1,076**	**$ 641**	**$ 137**	**$ 504**

	December 31, 2015						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Materials and supplies	$ 2,343	$ 785	$ 1,133	$ 776	$ 357	$ 81	$ 301
Coal	1,105	451	370	192	178	16	267
Natural gas, oil and other	298	40	248	120	128	8	2
Total inventory	$ 3,746	$ 1,276	$ 1,751	$ 1,088	$ 663	$ 105	$ 570

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 the Nuclear Decommissioning Trust Fund (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

Duke Energy, Progress Energy and Duke Energy Ohio 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 and Duke Energy Ohio 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 Investments and Other 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. 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. Significant changes in commodity prices, the condition of an asset or management's interest in selling the asset are generally viewed as triggering events to reassess cash flows.

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,		
	2016	**2015**	**2014**
Duke Energy	**2.8%**	2.9%	2.8%
Duke Energy Carolinas	**2.8%**	2.8%	2.7%
Progress Energy	**2.7%**	2.6%	2.5%
Duke Energy Progress	**2.6%**	2.6%	2.5%
Duke Energy Florida	**2.8%**	2.7%	2.7%
Duke Energy Ohio	**2.6%**	2.7%	2.3%
Duke Energy Indiana	**3.1%**	3.0%	3.0%

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. When it becomes probable that meters or other regulated mass utility assets will be abandoned, the cost of the asset and accumulated depreciation is reclassified to regulatory assets 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 a settlement among Duke Energy Florida, the Florida Office of Public Counsel (Florida OPC) and other customer advocates (the 2013 Settlement). Portions of the nuclear fuel balances that were under contract for sale were subsequently moved to Other within Current Assets and Other within Investments and Other Assets on the Consolidated Balance Sheets.

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.

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

	December 31,	
(in millions)	**2016**	**2015**
Duke Energy	**$ 831**	$ 677
Duke Energy Carolinas	**313**	283
Progress Energy	**161**	172
Duke Energy Progress	**102**	102
Duke Energy Florida	**59**	70
Duke Energy Ohio	**2**	3
Duke Energy Indiana	**32**	31

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)	**2016**	**2015**
Duke Energy Ohio	**$ 97**	$ 71
Duke Energy Indiana	**123**	97

Allowance for Doubtful Accounts

Allowances for doubtful accounts are presented in the following table.

	December 31,		
(in millions)	**2016**	**2015**	**2014**
Allowance for Doubtful Accounts			
Duke Energy	**$ 14**	$ 12	$ 14
Duke Energy Carolinas	**2**	3	3
Progress Energy	**6**	6	8
Duke Energy Progress	**4**	4	7
Duke Energy Florida	**2**	2	2
Duke Energy Ohio	**2**	2	2
Duke Energy Indiana	**1**	1	1
Allowance for Doubtful Accounts – VIEs			
Duke Energy	**$ 54**	$ 53	$ 51
Duke Energy Carolinas	**7**	7	6
Progress Energy	**7**	8	8
Duke Energy Progress	**5**	5	5
Duke Energy Florida	**2**	3	3

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 various business risks and losses, such as 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 a severance plan 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

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 entered into 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.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The largest amount of tax benefit that is greater than 50 percent likely of being effectively settled is recorded. Management considers a tax position effectively settled when: (i) the taxing authority has completed its examination procedures, including all appeals and administrative reviews; (ii) the Duke Energy Registrants do not intend to appeal or litigate the tax position included in the completed examination; and (iii) it is remote that the taxing authority would examine or re-examine the tax position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. If these unrecognized tax benefits are later recognized, then there will be a decrease in income tax expense or a reclassification between deferred and current taxes payable. If the portion of tax benefits that has been recognized changes and those tax benefits are subsequently unrecognized, then the previously recognized tax benefits may impact the financial statements through increasing income tax expense or a reclassification between deferred and current taxes payable. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties.

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 and Cash Grants

When Duke Energy receives ITCs or cash grants on wind or solar facilities, it reduces the basis of the property recorded on the Consolidated Balance Sheets by the amount of the ITC or cash grant and, therefore, the ITC or grant 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 or government grant. 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 as both operating revenues and property and other taxes in the Consolidated Statements of Operations were as follows.

	Years Ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Duke Energy	**$ 362**	$ 396	$ 498
Duke Energy Carolinas	**31**	31	94
Progress Energy	**213**	229	263
Duke Energy Progress	**18**	16	56
Duke Energy Florida	**195**	213	207
Duke Energy Ohio	**100**	102	103
Duke Energy Indiana	**17**	34	38

On July 23, 2013, North Carolina House Bill 998, or the North Carolina Tax Simplification and Rate Reduction Act (HB 998) was signed into law. HB 998 repealed the utility franchise tax effective July 1, 2014. The utility franchise tax was a 3.22 percent gross receipts tax on sales of electricity. The result of this change in law is an annual reduction in excise taxes of approximately $160 million for Duke Energy Carolinas and approximately $110 million for Duke Energy Progress. HB 998 also increases sales tax on electricity from 3 percent to 7 percent effective July 1, 2014. HB 998 requires the NCUC to adjust retail electric rates for the elimination of the utility franchise tax, changes due to the increase in sales tax on electricity and the resulting change in liability of utility companies under the general franchise tax.

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, 2016 and 2015, an insignificant amount of Duke Energy's consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

The following new accounting standards have been issued, but have not yet been adopted by the Duke Energy Registrants, as of December 31, 2016.

Goodwill Impairment. In January 2017, the Financial Accounting Standards Board (FASB) issued revised guidance for subsequent measurement of goodwill. Under the updated 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 is unable to determine the future impact of adopting this guidance.

For Duke Energy, this guidance is effective for interim and annual periods beginning January 1, 2020, but may be early adopted for interim or annual goodwill tests performed on testing dates after January 1, 2017. The guidance will be applied on a prospective basis.

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.

Most of Duke Energy's revenue is expected to 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, Duke Energy expects that the 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, Duke Energy does not expect that there will be a significant shift in the timing or pattern of revenue recognition for such sales. The evaluation of other revenue streams is ongoing, including long-term contracts with industrial customers and long-term purchase power agreements (PPA).

Duke Energy continues to evaluate what information would be most useful for users of the financial statements, including information already provided in disclosures outside of the financial statement footnotes. These additional disclosures could include the disaggregation of revenues by geographic location, type of service, customer class or by duration of contract ('at-will' versus contracted revenue). Revenues from contracts with customers, revenue recognized under regulated operations accounting and revenue from lease accounting will also be disclosed.

Duke Energy intends to use the modified retrospective method of adoption effective January 1, 2018. This method results in a cumulative change effect that will be recorded as an adjustment to retained earnings as of January 1, 2018, as if the standard had always been in effect. Disclosures for 2018 will include a comparison to what would have been reported for 2018 under the current revenue recognition rules in order 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.

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, although it can be early adopted. The guidance is applied using a modified retrospective approach. Duke Energy is currently evaluating the financial statement impact of adopting this standard. Other than an expected increase in assets and liabilities, the ultimate impact of the new standard has not yet been determined. Significant system enhancements may be required to facilitate the identification, tracking and reporting of potential leases based upon requirements of the new lease standard.

Stock-Based Compensation and Income Taxes. In March 2016, the FASB issued revised accounting guidance for stock-based compensation and the associated income taxes. This standard changes certain aspects of accounting for stock-based payment awards to employees including the accounting for income taxes, statutory tax withholding requirements, as well as classification on the Consolidated Statements of Cash Flows. The primary future impact to the Duke Energy Registrants is expected to be a small increase in the volatility of income tax expense. This guidance will be adopted prospectively, retrospectively, or using a modified retrospective approach depending on the item changed for the period beginning January 1, 2017.

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, although it can be early adopted. 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 in total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents explained when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. Prior to adoption, the Duke Energy Registrants reflect changes in restricted cash within Cash Flows from Investing Activities on the Consolidated Statement of Cash Flows.

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 change effect that will be recorded as an 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.

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.

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 an estimated fair value of approximately $2.0 billion at the time of the acquisition. Piedmont is a North Carolina corporation primarily engaged in regulated natural gas distribution to residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee. Piedmont is also invested in joint-venture, energy-related businesses, including regulated interstate natural gas transportation and storage and regulated intrastate natural gas transportation. 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.

Preliminary Purchase Price Allocation

The preliminary purchase price allocation of the Piedmont acquisition is estimated 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 were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows and market prices of long-term debt. The preliminary amounts are subject to revision to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date.

The majority of Piedmont’s operations are subject to the rate-setting authority of the NCUC, the PSCSC and the TRA 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 preliminary 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 estimated 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 platform, an improved risk profile and expected synergies resulting from the combined entities. See Note 11 for information related to the allocation of goodwill to Duke Energy's reporting units.

Accounting Charges Related to the Acquisition

Duke Energy incurred pretax non-recurring transaction and integration costs associated with the acquisition of $439 million and $9 million for the years ended December 31, 2016 and 2015, respectively. Amounts recorded on the Consolidated Statements of Operations 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.

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.

Purchase of NCEMPA's Generation

On July 31, 2015, Duke Energy Progress completed the purchase of North Carolina Eastern Municipal Power Agency’s (NCEMPA) ownership interests in certain generating assets, fuel and spare parts inventory jointly owned with and operated by Duke Energy Progress for approximately $1.25 billion. This purchase was accounted for as an asset acquisition. The purchase resulted in the acquisition of a total of approximately 700 megawatts (MW) of generating capacity at Brunswick Nuclear Plant (Brunswick), Shearon Harris Nuclear Plant (Harris), Mayo Steam Plant and Roxboro Steam Plant. In connection with this transaction, Duke Energy Progress and NCEMPA entered into a 30-year wholesale power agreement, whereby Duke Energy Progress will sell power to NCEMPA to continue to meet the needs of NCEMPA customers.

The purchase price exceeded the historical carrying value of the acquired assets by $350 million, which was recognized as an acquisition adjustment and recorded in property, plant and equipment. Duke Energy Progress established a rider in North Carolina to recover the costs to acquire, operate and maintain interests in the assets purchased as allocated to its North Carolina retail operations, including the purchase acquisition adjustment, and included the purchase acquisition adjustment in wholesale power formula rates.

Duke Energy Progress received an order from the PSCSC to defer recovery of the South Carolina retail allocated costs of the asset purchased until Duke Energy Progress' next general rate case, which was filed in July 2016. In October 2016, Duke Energy Progress, the Office of Regulatory Staff (ORS) and intervenors entered into a settlement agreement that provides for recovery of the historical carrying value of the South Carolina allocated purchased costs of the transaction. The settlement agreement was approved by the PSCSC in December 2016. See Note 4 for additional information on the South Carolina rate case.

The ownership interests in generating assets acquired are subject to rate-setting authority of the FERC, NCUC and PSCSC and accordingly, the assets are recorded at historical cost. The assets acquired are presented in the following table.

(in millions)		
Inventory	$	56
Net property, plant and equipment		845
Total assets		**901**
Acquisition adjustment, recorded within property, plant and equipment		350
Total purchase price	**$**	**1,251**

In connection with the acquisition, Duke Energy Progress acquired NCEMPA's NDTF assets of $287 million and assumed AROs of $204 million associated with NCEMPA's interest in the generation assets. The NDTF and the AROs are subject to regulatory accounting treatment.

DISPOSITIONS

The following table summarizes the (Loss) Income from Discontinued Operations, net of tax recorded on Duke Energy's Consolidated Statements of Operations:

	Years Ended December 31,					
(in millions)		**2016**		**2015**		**2014**
International Energy Disposal Group	**$**	**(534)**	$	157	$	(73)
Midwest Generation Disposal Group		**36**		33		(524)
Other[(a)]		**90**		(13)		(52)
(Loss) Income from Discontinued Operations, net of tax	**$**	**(408)**	$	177	$	(649)

(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 amounts for 2015 and 2014 include indemnifications provided for certain legal, tax and environmental matters and foreign currency translation adjustments.

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 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.

- 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 carrying values of the major classes of Assets held for sale and Liabilities associated with assets held for sale included in the Consolidated Balance Sheets. As a result of Duke Energy closing both transactions in December 2016, there are no Assets held for sale or Liabilities associated with assets held for sale as of December 31, 2016.

(in millions)		**December 31, 2015**
Current assets held for sale		
Cash and cash equivalents	$	474
Receivables, net		188
Inventory		65
Other		19
Total current assets held for sale		746
Noncurrent assets held for sale		
Property, Plant and Equipment		
Cost		2,859
Accumulated depreciation and amortization		(930)
Net property, plant and equipment		1,929
Goodwill		271
Other		213
Total noncurrent assets held for sale		2,413
Total assets held for sale	$	3,159
Current liabilities associated with assets held for sale		
Accounts payable	$	51
Taxes accrued		60
Current maturities of long-term debt		48
Other		120
Total current liabilities associated with assets held for sale		279
Noncurrent liabilities associated with assets held for sale		
Long-Term Debt		653
Deferred income taxes		157
Other		90
Total noncurrent liabilities associated with assets held for sale		900
Total liabilities associated with assets held for sale	$	1,179

The value of goodwill increased by $7 million from December 31, 2015 through the date of sale as a result of changes in foreign currency exchanges rates. At the time of the disposition, the International Disposal Group included goodwill of $278 million.

The following table presents the results of the International Disposal Group 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**	**2014**
Operating Revenues	**$ 988**	$ 1,088	$ 1,417
Fuel used in electric generation and purchased power	**227**	306	486
Cost of natural gas	**43**	53	63
Operation, maintenance and other	**341**	334	352
Depreciation and amortization[a]	**62**	92	97
Property and other taxes	**15**	7	9
Impairment charges [b]	**194**	13	—
(Loss) Gains on Sales of Other Assets and Other, net	**(3)**	6	6
Other Income and Expenses, net	**58**	23	47
Interest Expense	**82**	85	93
Pretax loss on disposal[c]	**(514)**	—	—
(Loss) Income before income taxes[d]	**(435)**	227	370
Income tax expense[e][f]	**99**	70	443
(Loss) Income from discontinued operations of the International Disposal Group	**$ (534)**	$ 157	$ (73)

(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, $221 million and $360 million for the years ended December 31, 2016, 2015 and 2014, 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 and 2014 amount includes an income tax charge of $373 million related to historical undistributed foreign earnings. 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**	**2014**
Cash flows provided by (used in):			
Operating activities	**$ 204**	$ 248	$ 339
Investing activities	**(434)**	177	111

Other Sale Related Matters

Duke Energy will provide transition services to CTG and I Squared for a period not to extend beyond March 2017 and September 2017, respectively. In addition, Duke Energy will reimburse CTG and I Squared 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.

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**	**2014**	**2016**	**2015**	**2014**
Operating Revenues	**$ —**	$ 543	$ 1,748	**$ —**	$ 412	$ 1,299
Pretax Loss on disposal[a]	**—**	(45)	(929)	**—**	(52)	(959)
Income (loss) before income taxes[b]	**$ —**	$ 59	$ (818)	**$ —**	$ 44	$ (863)
Income tax (benefit) expense[c]	**(36)**	26	(294)	**(36)**	21	(300)
Income (loss) from discontinued operations	**$ 36**	$ 33	$ (524)	**$ 36**	$ 23	$ (563)

(b) 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.

(c) 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.

(d) 2016 amounts result from immaterial out of period deferred tax liability adjustments.

3. BUSINESS SEGMENTS

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 in 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.

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.

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

Due to the Piedmont acquisition and the sale of International Energy in the fourth quarter of 2016, Duke Energy's segment structure has been realigned to include the following segments: Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables. Prior period information has been recast to conform to the current segment structure. See Note 2 for further information on the Piedmont and International Energy transactions.

Electric Utilities and Infrastructure 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.

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

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

In December 2016, Duke Energy closed on the sale of the International Disposal Group, which includes the former International Energy business segment, excluding the equity method investment in NMC. Results of the International Disposal Group are presented within Discontinued Operations for all periods and results of NMC are presented within Other for all periods, as described below. See Note 2, "Acquisitions and Dispositions" for additional information related to the sale.

The remainder of Duke Energy’s operations is presented as Other, which is primarily comprised of unallocated 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). As discussed above, Other also includes Duke Energy's 25 percent interest in NMC, a large regional producer of methyl tertiary butyl ether (MTBE) located in Saudi Arabia. The investment in NMC is accounted for under the equity method of accounting.

	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 earnings (losses) 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.

	Year Ended December 31, 2014						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 21,655	$ 573	$ 235	$ 22,463	$ 46	$ —	$ 22,509
Intersegment Revenues	36	5	1	42	70	(112)	—
Total Revenues	$ 21,691	$ 578	$ 236	$ 22,505	$ 116	$ (112)	$ 22,509
Interest Expense	$ 1,057	$ 37	$ 50	$ 1,144	$ 409	$ (24)	$ 1,529
Depreciation and amortization	2,686	73	90	2,849	120	—	2,969
Equity in earnings (losses) of unconsolidated affiliates	(1)	—	8	7	123	—	130
Income tax expense (benefit)	1,582	45	(88)	1,539	(314)	—	1,225
Segment income (loss) (a)(b)	2,714	80	53	2,847	(332)	18	2,533
Add back noncontrolling interest component							5
Loss from discontinued operations, net of tax(c)							(649)
Net income							$ 1,889
Capital investments expenditures and acquisitions(d)	$ 4,642	$ 121	$ 514	$ 5,277	$ 251	$ —	$ 5,528
Segment assets(e)	104,119	2,512	2,981	109,612	10,755	190	120,557

(a) Other includes a $94 million pretax impairment charge related to Ohio Valley Electric Corporation (OVEC) and costs to achieve mergers.

(b) Electric Utilities and Infrastructure includes pretax charges of $102 million related to the criminal investigation of the Dan River coal ash spill. See Note 5 for additional information.

(c) Includes an impairment of the Midwest Generation Disposal Group. Refer to Note 2 for further information.

(d) Other includes $67 million of capital investments expenditures and acquisitions of the International Disposal Group.

(e) Other includes Assets Held for Sale balances related to the International Disposal Group and Midwest Generation Disposal Group. Refer to Note 2 for further information.

Geographical Information

For the years ended December 31, 2016, 2015 and 2014, all assets and revenues are within the U.S.

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
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
2014					
Electric Utilities and Infrastructure	$ 19,007	$ 1,879	$ —	$ 805	$ 21,691
Gas Utilities and Infrastructure	—	—	571	7	578
Commercial Renewables	—	236	—	—	236
Total Reportable Segments	$ 19,007	$ 2,115	$ 571	$ 812	$ 22,505

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 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.

Other 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 power plants. For additional information on related party transactions refer to Note 13. All of Duke Energy Ohio's revenues are generated domestically and its long-lived assets are all in the U.S.

	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

	Year Ended December 31, 2014					
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Total revenues	$ 1,317	$ 578	$ 1,895	$ 19	$ (1)	$ 1,913
Interest expense	$ 43	$ 37	$ 80	$ 5	$ 1	$ 86
Depreciation and amortization	138	73	211	3	—	214
Income tax expense (benefit)	71	45	116	(73)	—	43
Segment income (loss)[a]	122	80	202	(133)	(1)	68
Loss from discontinued operations, net of tax[b]						(563)
Net loss						$ (495)
Capital expenditures	$ 193	$ 107	$ 300	$ 22	$ —	$ 322
Segment assets[c]	4,428	2,487	6,915	3,321	(243)	9,993

(a) Other includes a $94 million pretax impairment charge related to OVEC.
(b) Includes an impairment of the Midwest Generation Disposal Group. Refer to Note 2 for further information.
(c) Other includes Assets Held for Sale balances related to the Midwest Generation Disposal Group. Refer to Note 2 for further information.

DUKE ENERGY CAROLINAS, PROGRESS ENERGY, DUKE ENERGY PROGRESS, DUKE ENERGY FLORIDA AND DUKE ENERGY INDIANA

The remaining Subsidiary Registrants each have one reportable operating segment, Electric Utilities and Infrastructure, which generates, transmits, distributes and sells electricity. The remainder of each company's operations is classified as Other. While not considered a reportable segment for any of these companies, Other consists of certain unallocated corporate costs. Other for Progress Energy also includes interest expense on corporate debt instruments of $221 million, $240 million and $241 million for the years ended December 31, 2016, 2015 and 2014. The following table summarizes the net loss for Other for each of these entities.

	Years Ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Duke Energy Carolinas	**$ (104)**	$ (95)	$ (79)
Progress Energy	**(200)**	(159)	(190)
Duke Energy Progress	**(56)**	(32)	(31)
Duke Energy Florida	**(23)**	(16)	(19)
Duke Energy Indiana	**(13)**	(10)	(11)

The assets of Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana are substantially all included within the Electric Utilities and Infrastructure segment at December 31, 2016, 2015 and 2014.

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.

	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							
AROs – coal ash	$ 3,761	$ 1,536	$ 1,830	$ 1,822	$ 8	$ 12	$ 276
AROs – nuclear and other	684	9	569	275	294	—	—
Accrued pension and OPEB	2,387	481	882	423	458	135	222
Retired generation facilities	534	39	422	165	257	—	73
Debt fair value adjustment	1,313	—	—	—	—	—	—
Net regulatory asset related to income taxes	894	484	231	7	224	63	119
Storm cost deferrals	153	—	148	148	—	5	—
Nuclear asset securitized balance, net	1,193	—	1,193	—	1,193	—	—
Hedge costs and other deferrals	217	93	91	66	25	7	26
Derivatives – gas supply contracts	187	—	—	—	—	—	—
Demand side management (DSM)/Energy efficiency (EE)	407	122	278	263	15	6	—
Grid Modernization	65	—	—	—	—	65	—
Vacation accrual	196	76	38	38	—	4	10
Deferred fuel and purchased power	156	—	111	24	87	5	40
Nuclear deferral	226	92	134	38	96	—	—
Post-in-service carrying costs and deferred operating expenses	413	70	42	42	—	20	281
Gasification services agreement buyout	8	—	—	—	—	—	8
Transmission expansion obligation	71	—	—	—	—	71	—
Manufactured gas plant (MGP)	99	—	—	—	—	99	—
Advanced metering infrastructure	218	172	—	—	—	—	46
NCEMPA deferrals	51	—	51	51	—	—	—
East Bend deferrals	32	—	—	—	—	32	—
Other	636	223	103	69	36	33	121
Total regulatory assets	13,901	3,397	6,123	3,431	2,693	557	1,222
Less: current portion	1,023	238	401	188	213	37	149
Total noncurrent regulatory assets	$ 12,878	$ 3,159	$ 5,722	$ 3,243	$ 2,480	$ 520	$ 1,073

	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 Liabilities							
Costs of removal	$ **6,074**	$ **2,476**	$ **2,198**	$ **1,840**	$ **358**	$ **212**	$ **660**
Amounts to be refunded to customers	**45**	**—**	**—**	**—**	**—**	**—**	**45**
Storm reserve	**83**	**22**	**60**	**—**	**60**	**1**	**—**
Accrued pension and OPEB	**174**	**46**	**—**	**—**	**—**	**19**	**72**
Deferred fuel and purchased power	**192**	**105**	**81**	**64**	**17**	**6**	**—**
Other	**722**	**352**	**245**	**200**	**44**	**19**	**11**
Total regulatory liabilities	**7,290**	**3,001**	**2,584**	**2,104**	**479**	**257**	**788**
Less: current portion	**409**	**161**	**189**	**158**	**31**	**21**	**40**
Total noncurrent regulatory liabilities	$ **6,881**	$ **2,840**	$ **2,395**	$ **1,946**	$ **448**	$ **236**	$ **748**

	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Regulatory Assets							
AROs – coal ash	$ 2,555	$ 1,120	$ 1,394	$ 1,386	$ 8	$ 4	$ 37
AROs – nuclear and other	838	104	487	195	292	—	—
Accrued pension and OPEB	2,151	479	807	366	441	139	220
Retired generation facilities	509	49	409	179	230	—	51
Debt fair value adjustment	1,191	—	—	—	—	—	—
Net regulatory asset related to income taxes	1,075	564	318	106	212	55	120
Nuclear asset securitizable balance, net	1,237	—	1,237	—	1,237	—	—
Hedge costs and other deferrals	571	127	410	171	239	7	27
DSM/EE	340	80	250	237	13	10	—
Grid Modernization	68	—	—	—	—	68	—
Vacation accrual	192	79	38	38	—	5	10
Deferred fuel and purchased power	151	21	129	93	36	1	—
Nuclear deferral	245	107	138	62	76	—	—
Post-in-service carrying costs and deferred operating expenses	383	97	38	38	—	21	227
Gasification services agreement buyout	32	—	—	—	—	—	32
Transmission expansion obligation	72	—	—	—	—	72	—
MGP	104	—	—	—	—	104	—
NCEMPA deferrals	21	—	21	21	—	—	—
East Bend deferrals	16	—	—	—	—	16	—
Other	499	244	121	82	39	31	94
Total regulatory assets	12,250	3,071	5,797	2,974	2,823	533	818
Less: current portion	877	305	362	264	98	36	102
Total noncurrent regulatory assets	$ 11,373	$ 2,766	$ 5,435	$ 2,710	$ 2,725	$ 497	$ 716

	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Regulatory Liabilities							
Costs of removal	$ 5,329	$ 2,413	$ 2,078	$ 1,725	$ 353	$ 222	$ 616
Amounts to be refunded to customers	71	—	—	—	—	—	71
Storm reserve	150	24	125	—	125	1	—
Accrued pension and OPEB	288	68	51	25	26	21	83
Deferred fuel and purchased power	311	55	255	58	197	1	—
Other	506	281	164	155	8	12	46
Total regulatory liabilities	6,655	2,841	2,673	1,963	709	257	816
Less: current portion	400	39	286	85	200	12	62
Total noncurrent regulatory liabilities	$ 6,255	$ 2,802	$ 2,387	$ 1,878	$ 509	$ 245	$ 754

Descriptions of regulatory assets and liabilities, summarized in the tables above, as well as their recovery and amortization periods follow. Items are excluded from rate base unless otherwise noted.

AROs – coal ash. Represents regulatory assets including deferred depreciation and accretion related to the legal obligation to close ash basins. The costs are deferred until recovery treatment has been determined. The recovery period for these costs has yet to be established. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Ohio earn a debt return on their expenditures. See Notes 1 and 9 for additional information.

AROs – nuclear and other. Represents regulatory assets, 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 on NDTF investments. The recovery period for costs related to nuclear facilities runs through the decommissioning period of each nuclear unit, the latest of which is currently estimated to be 2086. 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 average remaining service periods of active employees covered by the benefit plans, which is approximately 9 years. See Note 21 for additional detail.

Retired generation facilities. Duke Energy Carolinas earns a return on the outstanding retail balance with recovery periods ranging from one to six years. Duke Energy Progress earns a return on the outstanding balance with recovery over a period of 10 years beginning in 2013 for retail purposes and over the longer of 10 years or the previously estimated planned retirement date for wholesale purposes. Duke Energy Indiana earns a return on the outstanding balances and the costs are included in rate base. Duke Energy Indiana's recovery period will be determined in the next general rate case. Duke Energy Florida earns a full return on a portion of the regulatory asset related to the retired nuclear plant currently recovered in the nuclear cost recovery clause (NCRC), with the remaining portion earning a reduced return. Duke Energy Florida's recovery period varies.

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 related to income taxes. Regulatory assets principally associated with the depreciation and recovery of AFUDC equity. Amounts have no impact on rate base as regulatory assets are offset by deferred tax liabilities. The recovery period is over the life of the associated assets. Amounts for all registrants include regulatory liabilities related to the gross up of federal ITCs. Amounts for Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress include regulatory liabilities related to the change in the North Carolina corporate tax rate discussed in Note 22.

Storm cost deferrals. Represents deferred incremental costs incurred related to extraordinary weather-related events, primarily damage resulting from Hurricane Matthew in the fourth quarter of 2016. The recovery period is unknown.

Nuclear asset securitizable 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. The recovery period is through 2036.

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. The recovery period varies for these costs and currently extends to 2048.

Derivatives – gas supply contracts held for utility operations. Represents costs for certain long-dated, fixed quantity forward gas supply contracts which are recoverable through Piedmont's PGA clauses.

DSM/EE. The recovery period varies for these costs, with some currently unknown. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are required to pay interest on the outstanding liability balance. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida collect a return on DSM/EE investments.

Grid Modernization. Duke Energy Ohio 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. Recovery period is generally one year for depreciation and operating expenses. Recovery for post-in-service carrying costs is over the life of the assets. Duke Energy Ohio is earning a return on these costs.

Vacation accrual. Generally recovered within one year. Duke Energy Carolinas earns a return on the North Carolina balance.

Deferred fuel and purchased power. Represents certain energy-related costs that are recoverable or refundable as approved by the applicable regulatory body. Duke Energy Florida amount includes capacity costs. Duke Energy Florida earns a return on the retail portion of under-recovered costs. Duke Energy Ohio earns a return on under-recovered costs. Duke Energy Florida and Duke Energy Ohio pay interest on over-recovered costs. Duke Energy Carolinas and Duke Energy Progress amounts include certain purchased power costs in both North Carolina and South Carolina and costs of distributed energy resource programs in South Carolina. Duke Energy Carolinas and Duke Energy Progress pay interest on over-recovered costs in North Carolina. Recovery period is generally over one year. Duke Energy Indiana recovery period is quarterly.

Nuclear deferral. Includes (i) amounts related to levelizing nuclear plant outage costs at Duke Energy Carolinas and Duke Energy Progress in North Carolina and South Carolina, 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 and (ii) certain deferred preconstruction and carrying costs at Duke Energy Florida as approved by the FPSC, primarily associated with the Levy nuclear project (Levy), with a final true-up to be filed by May 2017.

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. Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio and Duke Energy Indiana earn a return on the outstanding balance. For Duke Energy Ohio and Duke Energy Indiana, some amounts are included in rate base. Recovery is over various lives and the latest recovery period is 2083.

Gasification services agreement buyout. The IURC authorized Duke Energy Indiana to recover costs incurred to buyout a gasification services agreement, including carrying costs through 2017. Duke Energy Indiana earns a return on this balance.

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. Costs incurred between 2008 and 2012 are recovered through an approved MGP rider. Recovery of costs incurred after 2012 has been requested but is pending approval from the PUCO. Duke Energy Ohio does not earn a return on these costs.

Advanced metering infrastructure (AMI). Duke Energy Carolinas amount represents deferred costs related to the installation of AMI meters and remaining net book value of non-AMI meters to be replaced. Duke Energy Carolinas earns a return on a portion of the costs and the recovery period varies. Duke Energy Indiana amount represents expected future recovery of net book value of electromechanical meters that have been replaced with AMI meters. Duke Energy Indiana expects to recover this asset over a six-year period and the meters will remain in rate base until the next general rate case.

NCEMPA deferrals. Represents retail allocated cost deferrals and returns associated with the additional ownership interest in assets acquired from NCEMPA discussed in Note 2. The North Carolina retail allocated costs are generally being recovered over a period of time between three years and the remaining life of the assets purchased through a rider that became effective on December 1, 2015. The South Carolina retail allocated costs will be amortized over an average of 24 years beginning January 2017 are earning a return.

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. Recovery will not commence until resolution of the next electric rate case in Kentucky. Duke Energy Ohio is earning a return on these deferred costs.

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. The period of refund for Duke Energy Indiana is through 2018.

Storm reserve. Duke Energy Carolinas and Duke Energy Florida are allowed to petition the PSCSC and FPSC, respectively, to seek recovery of incremental or allowable costs incurred for named storms. Funds are used to offset future incurred costs.

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 Duke Energy Corporation Holding Company (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 and Articles of Incorporation 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, 2016.

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 net assets at December 31, 2016.

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, TRA 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.

Duke Energy Carolinas and Duke Energy Progress

Ash Basin Closure Costs Deferral

On July 13, 2016, in response to a joint petition of Duke Energy Carolinas and Duke Energy Progress, the PSCSC issued an accounting order for the deferment into a regulatory account 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 South Carolina. The decision allows for ash basin closure expenses to be partially offset with excess regulatory liability amounts from the deferral of nuclear decommissioning costs that are collected from South Carolina retail customers and for Duke Energy Progress to partially offset incurred ash basin closure costs with costs of removal amounts collected from customers. The PSCSC's ruling does not change retail rates or the tariff amounts and does not limit the ability of interested parties to challenge the reasonableness of expenditures in subsequent proceedings. In connection with Duke Energy Progress' base rate case filed in July 2016, in December 2016, the PSCSC approved recovery of coal ash costs incurred from January 1, 2015, through June 30, 2016, over a 15-year period and ongoing deferral of future ash basin closure costs incurred from July 1, 2016, until its next base rate case in South Carolina.

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 are due by March 1, 2017, and reply comments are due by March 29, 2017. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

FERC Transmission Return on Equity Complaints

On January 7, 2016, a group of transmission service customers filed a complaint with FERC that the rate of return on equity of 10.2 percent in Duke Energy Carolinas' transmission formula rates is excessive and should be reduced to no higher than 8.49 percent, effective upon the complaint date. On the same date, a similar complaint was filed with FERC claiming that the rate of return on equity of 10.8 percent in Duke Energy Progress' transmission formula rates is excessive and should be reduced to no higher than 8.49 percent, effective upon the complaint date. On April 21, 2016, FERC issued an order which consolidated the cases, set a refund effective date of January 7, 2016, and set the consolidated case for settlement and hearing. On June 14, 2016, Duke Energy Carolinas and Duke Energy Progress reached a settlement agreement in principle to reduce the return on equity for both companies to 10 percent. On November 21, 2016, the FERC approved the settlement agreement resolving the complaints. The Impact on results of operations, cash flows and the financial position of Duke Energy Carolinas and Duke Energy Progress will not be material.

Duke Energy Carolinas

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 AFUDC. The project is expected to be commercially available in late 2017. 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. Duke Energy Carolinas filed its response on June 13, 2016, and SCCL and SACE filed a reply on June 23, 2016. On September 6, 2016, the Small Business Chamber of Commerce filed a motion for permission to file a brief supporting the environmental intervenors’ position. On September 22, 2016, the South Carolina Supreme Court granted permission for the brief and allowed Duke Energy Carolinas an opportunity to file a response, which was filed on October 3, 2016. Duke Energy Carolinas cannot predict the outcome of this matter.

William States Lee III 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 have 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. As of December 31, 2016, Duke Energy Carolinas has incurred approximately $520 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 is not required to build the nuclear reactors as result of the COLs being issued.

Duke Energy Progress

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. Current estimated incremental operation and maintenance and capital costs total approximately $140 million. Additional costs could be incurred in 2017 related to storms in the fourth quarter of 2016. Duke Energy Progress proposes to true-up the total costs quarterly through August 2017. 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. Estimated total restoration costs are approximately $60 million. Actual total costs would be trued-up quarterly through 2017. In January 2017, the PSCSC approved the deferral request and issued an accounting order.

South Carolina Rate Case

On July 1, 2016, Duke Energy Progress filed an application with the PSCSC requesting an average 14.5 percent increase in retail revenues. The requested rate change would increase annual revenues by approximately $79 million, with a rate of return on equity of 10.75 percent. The increase is designed to recover the cost of investment in new generation infrastructure, environmental expenditures including allocated historical ash basin closure costs and increased nuclear operating costs. Duke Energy Progress has requested new rates to be effective January 1, 2017. On October 19, 2016, Duke Energy Progress, the ORS and intervenors entered into a settlement agreement that was filed with the PSCSC on the same day. Terms of the settlement agreement include 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 will be effective January 1, 2018. Duke Energy Progress will amortize approximately $18.5 million from the cost of removal reserve in 2017. Other settlement terms include 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. In December 2016, the PSCSC approved the settlement and issued an approval order.

Western Carolinas Modernization Plan

On November 4, 2015, in response to community feedback, Duke Energy Progress announced a revised Western Carolinas Modernization Plan with an estimated cost of $1.1 billion. The revised plan includes 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 revised plan includes upgrades to existing transmission lines and substations, but eliminates the need for a new transmission line and a new substation associated with the project in South Carolina. The revised plan has the same overall project cost as the original plan and the plans to install solar generation remain unchanged. Duke Energy Progress has also proposed to add 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. The plan requires various approvals including regulatory approvals in North Carolina.

Duke Energy Progress filed for a Certificate of Public Convenience and Necessity (CPCN) with the NCUC for the new natural gas units on January 15, 2016. On March 28, 2016, the NCUC issued an order approving the 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. Site preparation activities are underway and construction of these plants is scheduled to begin in early 2017. The plants are expected to be in service by late 2019. Duke Energy Progress plans to file for future approvals related to the proposed solar generation and pilot battery storage project.

On May 27, 2016, N.C. Waste Awareness and Reduction Network (NC WARN) and The Climate Times filed a notice of appeal from the CPCN order to the N.C. Court of Appeals. On May 31, 2016, Duke Energy Progress filed a motion to dismiss the notice of appeal with the NCUC due to NC WARN's and The Climate Times' failure to post a required appeal bond. After a series of filings, an NCUC order, petitions to the N.C. Court of Appeals and an evidentiary hearing, on July 8, 2016, the NCUC issued an order setting NC WARN's and The Climate Times' appeal bond at $98 million. On July 28, 2016, NC WARN and The Climate Times filed a notice of appeal and exceptions from the NCUC's July 8, 2016, appeal bond order. On August 2, 2016, the NCUC granted Duke Energy Progress' motion to dismiss NC WARN's and The Climate Times' notice of appeal from the CPCN order due to failure to post the requisite bond. On August 18, 2016, NC WARN and The Climate Times filed a petition with the N.C. Court of Appeals seeking appellate review of the NCUC's CPCN order, the July 8, 2016, appeal bond order and the August 2, 2016, order dismissing their notice of appeal, which the N.C. Court of Appeals denied on September 6, 2016. On September 19, 2016, the NCUC granted Duke Energy Progress' motion to dismiss NC WARN's and The Climate Times' subsequent appeal of the second bond order dated July 28, 2016, and NC WARN's and The Climate Times' subsequent appeal of the CPCN order and dismissal order dated August 18, 2016. On October 17, 2016, NC WARN and The Climate Times filed another petition for review with the N.C. Court of Appeals asking the court to reverse the CPCN order, the second bond order and the dismissal of their first and second notices of appeal as to the CPCN order. On November 3, 2016, the N.C. Court of Appeals denied NC WARN's and The Climate Times' petition for review. All appeals have been concluded.

The carrying value of the 376 MW Asheville coal-fired plant, including associated ash basin closure costs, of $492 million and $548 million are included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2016 and 2015, 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 have approved deferral for $48 million of retail costs which 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.

Duke Energy Florida

Hines Chiller Uprate Project

On May 20, 2016, 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 (Hines). Duke Energy Florida proposed to complete the Uprate Project in two phases: Phase one to include work on Hines units 1-3 and common equipment, to be placed in service during October 2016; and Phase two work on Hines Unit 4 to be placed in service during January 2017. The final combined construction cost estimate for both phases of approximately $150 million is below the cost estimate provided during the need determination proceeding. Duke Energy Florida estimated an annual retail revenue requirement for Phase one and Phase two of approximately $17 million and $3 million, respectively. On August 29, 2016, the FPSC approved the Phase one revenue requirement to be effective in customer rates in November 2016. However, Duke Energy Florida made filings with the FPSC in October 2016 to remove the Uprate Project from customer rates because a portion of the common equipment required for either phase to be considered in service was not completed as expected. Duke Energy Florida filed for recovery of the costs associated with the Uprate Project in February 2017. Duke Energy Florida cannot predict the outcome of this matter.

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.

Purchase of Osprey Energy Center

In December 2014, Duke Energy Florida and Osprey Energy Center, LLC, a wholly owned subsidiary of Calpine Corporation (Calpine), entered into an Asset Purchase and Sale Agreement for the purchase of a 599 MW combined-cycle natural gas plant in Auburndale, Florida (Osprey Plant acquisition) for approximately $166 million. On August 2, 2016, Duke Energy Florida filed a petition seeking approval to include in base rates the revenue requirements for the Osprey Plant acquisition to be included in customer bills beginning in February 2017. Duke Energy Florida estimated the retail revenue requirements for the Osprey acquisition to be approximately $48 million. On November 1, 2016, the FPSC approved the petition to include the revenue requirements in base rates. Closing of the acquisition occurred on January 3, 2017.

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. 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. The stipulation is subject to court approval. Duke Energy recorded a reserve in the fourth quarter of 2016.

FPSC Settlement Agreements

On February 22, 2012, the FPSC approved a settlement agreement (the 2012 Settlement) among Duke Energy Florida, the Florida OPC and other customer advocates. The 2012 Settlement was to continue through the last billing cycle of December 2016. On October 17, 2013, the FPSC approved a settlement agreement (the 2013 Settlement) between Duke Energy Florida, Florida OPC and other customer advocates. The 2013 Settlement replaces and supplants the 2012 Settlement and substantially resolves issues related to (i) Crystal River Unit 3, (ii) Levy, (iii) Crystal River 1 and 2 coal units and (iv) future generation needs in Florida. Refer to the remaining sections below for further discussion of these settlement agreements.

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, 2016, Duke Energy Florida has deferred approximately $93 million for recovery associated with building the ISFSI.

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 years period that began in 2013 with a remaining uncollected balance of $128 million at December 31, 2016.

Crystal River Unit 3 Regulatory Asset

On May 22, 2015, Duke Energy Florida petitioned the FPSC for approval to include in base rates the revenue requirement for the projected $1.298 billion Crystal River Unit 3 regulatory asset as authorized by the 2013 Revised and Restated Stipulation and Settlement Agreement (2013 Agreement). 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 the third quarter of 2015 to adjust the regulatory asset balance.

In June 2015, the governor of Florida signed legislation to allow utilities to issue nuclear asset-recovery bonds to finance the recovery of certain retired nuclear generation assets, with approval of the FPSC. 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 Agreement 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 Notes 6 and 17 for additional information.

Customer Rate Matters

Pursuant to the 2013 Settlement, Duke Energy Florida will maintain base rates at the current level through the last billing period of 2018, subject to the return on equity range of 9.5 percent to 11.5 percent, with exceptions for base rate increases for new generation through 2018, per the provisions of the 2013 Settlement. Duke Energy Florida is not required to file a depreciation study, fossil dismantlement study or nuclear decommissioning study until the earlier of the next rate case filing or March 31, 2019. The 2013 Settlement also provided for a $150 million increase in base revenue effective with the first billing cycle of January 2013. If Duke Energy Florida’s retail base rate earnings fall below the return on equity range, as reported on a FPSC-adjusted or pro forma basis on a monthly earnings surveillance report, it may petition the FPSC to amend its base rates during the term of the 2013 Settlement.

Levy Nuclear Project

On July 28, 2008, Duke Energy Florida applied to the NRC for a COL for two Westinghouse AP1000 reactors at Levy. 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.

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 and to bring existing work to an orderly conclusion, including but not limited to costs to demobilize and cancel certain equipment and material orders placed. Duke Energy Florida recorded an exit obligation in 2014 for the termination of the EPC. This liability was recorded within Other in Deferred Credits and Other 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.

The 2012 Settlement provided that Duke Energy Florida include the allocated wholesale cost of Levy as a retail regulatory asset and include this asset as a component of rate base and amortization expense for regulatory reporting. In accordance with the 2013 Settlement, Duke Energy Florida ceased amortization of the wholesale allocation of Levy investments against retail rates.

On October 27, 2014, the FPSC approved Duke Energy Florida rates for 2015 for Levy as filed and consistent with those established in the 2013 Revised and Restated Settlement Agreement. Recovery of the remaining retail portion of the project costs may occur over 5 years from 2013 through 2017. Duke Energy Florida has an ongoing responsibility to demonstrate prudency related to the wind down of the Levy investment and the potential for salvage of Levy assets. As of December 31, 2016, Duke Energy Florida has a net uncollected investment in Levy of approximately $219 million, including AFUDC. Of this amount, $119 million related to land and the COL is included in Net, property, plant and equipment and will be recovered through base rates and $100 million is included in Regulatory assets within Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets and will be recovered through the NCRC.

On April 16, 2015, the FPSC approved Duke Energy Florida's petition to cease collection of the Levy Nuclear Project fixed charge beginning with the first billing cycle in May 2015. On August 18, 2015, the FPSC approved leaving the Levy Nuclear Project portion of the NCRC charge at zero dollars for 2016 and 2017, consistent with the 2013 Settlement. Duke Energy Florida will submit by May 2017 a true-up of Levy Nuclear Project costs or credits to be recovered no earlier than January 2018. To the extent costs become known after May 2017, Duke Energy Florida will petition for recovery at that time.

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 will likely be retired by 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. In April 2014, the FPSC approved Duke Energy Florida's petition to allow for the recovery of prudently incurred costs to comply with the Mercury and Air Toxics Standard through the Environmental Cost Recovery Clause.

Duke Energy Ohio

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 necessitated by current and proposed EPA regulations. Duke Energy Kentucky is targeting a completion date in fourth quarter 2018 for these projects and estimates a total cost of approximately $93 million. Duke Energy Kentucky has requested an order to be issued by April 30, 2017.

Base Rate Case

In connection with Duke Energy Ohio’s deployment of SmartGrid network, consisting of investments in AMI and distribution automation, a rider was established to recover these investments and return expected savings to customers. A stipulation updating this rider was approved by the PUCO in 2012, whereby Duke Energy Ohio committed to filing a base electric distribution case within one year of full deployment of SmartGrid. On October 22, 2015, PUCO staff concluded that full deployment had occurred thereby, absent relief by the PUCO, Duke Energy Ohio would be required to file a base electric rate case. Pursuant to an order (PUCO order) authorizing a modification in the filing date, Duke Energy Ohio notified the PUCO of its intent to file an electric distribution rate case in Ohio. The base rate case application and supporting testimony will be filed March 2, 2017, and March 16, 2017, respectively. 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. The proposed project involves the installation of a natural gas line and is estimated to cost between $86 million and $110 million, excluding AFUDC. On September 13, 2016, Duke Energy Ohio filed with the Ohio Power Siting Board for approval of one of two proposed routes. If approved, construction of the pipeline extension is expected to be completed by 2019.

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 AMI. Duke Energy Kentucky anticipates that the estimated $49 million project, if approved, will take about two years to complete. Duke Energy Kentucky also requested approval to establish a regulatory asset of approximately $10 million for the remaining book value of existing meter equipment and inventory that will be replaced. On July 20, 2016, the Kentucky Attorney General, the only intervenor in the proceeding, moved to dismiss the application. Duke Energy Kentucky filed its opposition to the Kentucky Attorney General's motion to dismiss on July 27, 2016. On September 28, 2016, the KPSC denied the Kentucky Attorney General's motion to dismiss and granted Duke Energy Kentucky's motion to file rebuttal testimony. Duke Energy Kentucky and the Kentucky Attorney General entered into a stipulation resolving the matters raised in the application. An evidentiary hearing was held on December 8, 2016. Duke Energy Kentucky cannot predict the outcome of this matter.

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 current projected total capital and operations and maintenance expenditures under the ASRP are approximately $240 million. The filing also sought approval of 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. The PUCO did, however, encourage Duke Energy Ohio to work with the PUCO Staff and intervenors to identify a reasonable solution for the risks attributed to service line leaks caused by corrosion. Duke Energy Ohio filed an application for rehearing of the PUCO decision. In December 2016, the PUCO granted the request for the purpose of further review. Duke Energy Ohio cannot predict the outcome of this matter.

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. After a comment period, 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 to 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 July 8, 2015. On January 6, 2016, Duke Energy Ohio and PUCO Staff entered into a stipulation pending PUCO approval, resolving the issues related to, among other things, performance incentives and the PUCO Staff audit of 2013 costs. Based on the stipulation, in December 2015, Duke Energy Ohio re-established approximately $20 million of the revenues that had been reversed in the second quarter. On October 26, 2016, the PUCO issued an order approving the stipulation without modification. Intervenors requested rehearing of the PUCO decision and, in December 2016, the PUCO granted rehearing for the purpose of further review. 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.

During May and November 2016, Duke Energy Ohio completed two competitive bidding processes with results approved by the PUCO to procure a portion of the supply for its SSO load for the term of the ESP. In 2016, Duke Energy Ohio also issued requests for proposal (RFP) to serve a portion of the load attributed to its customers on the state’s percentage of income payment plan. This RFP was issued consistent with state law enacted in 2016.

2012 Natural Gas Rate Case/Manufactured Gas Plant 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 that appeal remains pending. Oral argument is scheduled for February 28, 2017. Incurred and projected investigation and remediation expenses at these MGP sites that have not been collected through the MGP rider are approximately $99 million and are recorded as Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheet as of December 31, 2016. Duke Energy Ohio cannot predict the outcome of this matter.

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. The PUCO order authorized Duke Energy Ohio to seek to extend these deadlines due to certain circumstances. On May 16, 2016, Duke Energy Ohio filed an application to extend the deadline for cost recovery applicable to the East End site. In December 2016, the PUCO approved the request, extending the deadline to complete the remediation work until 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, 2016, $46 million of the regulatory asset represents future remediation cost expected to be incurred at the East End site. Duke Energy Ohio cannot predict the outcome of this matter.

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 Deferred credits and other 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, 2016 and 2015, $71 million and $72 million are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets, respectively.

(in millions)	December 31, 2015	Provisions/ Adjustments	Cash Reductions	December 31, 2016
Duke Energy Ohio	$ 92	**$ 3**	**$ (5)**	**$ 90**

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. Duke Energy Ohio cannot predict the outcome of this matter.

Duke Energy Indiana

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 Coal Combustion Residual (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 has requested timely recovery of approximately $380 million in retail capital costs and incremental operating and maintenance costs, including AFUDC, under a federal mandate tracker which 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 may be recoverable in the next rate case. Terms of the settlement agreement also require Duke Energy Indiana to perform certain reporting and groundwater monitoring. The settlement is subject to approval by the IURC. An evidentiary hearing was held on February 23, 2017. Duke Energy Indiana cannot predict the outcome of this matter.

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.

Duke Energy Indiana and several intervenors agreed upon a settlement (IGCC settlement) in 2015 to resolve disputes related to five IGCC riders (the 11th through 15th) and a subdocket to Duke Energy Indiana's fuel adjustment clause. The settlement agreement resolved disputes related to the determination on whether the IGCC plant was properly declared in-service for ratemaking purposes in June 2013, as well as the operational performance of the plant. 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 are subject to certain caps during the years of 2016 and 2017. The IGCC settlement also includes 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 and not earn a carrying cost. On August 24, 2016, the IURC approved the settlement in full with no changes or conditions. The order was not appealed and the proceeding is concluded. As of December 31, 2016, deferred costs related to the project are approximately $161 million. Under the IGCC settlement, future IGCC riders will be filed annually, rather than every six months, with the next filing scheduled for first quarter 2017.

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. The intervenors could appeal this order.

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 latest complaint, filed on February 12, 2015, claims the base rate of return on equity should be reduced to 8.67 percent and requests a consolidation of complaints. The motion to consolidate complaints was denied. On January 5, 2015, the FERC issued an order accepting the MISO transmission owners 0.50 percent adder 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. A hearing in the base return on equity proceeding was held in August 2015. 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. 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. 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 August 29, 2014, pursuant to a new statute, Duke Energy Indiana filed a seven-year grid infrastructure improvement plan with the IURC with an estimated cost of $1.9 billion, focusing on the reliability, integrity and modernization of the transmission and distribution system. The plan also provided for cost recovery through a transmission and distribution rider (T&D Rider). In May 2015, the IURC denied the original proposal due to an insufficient level of detailed projects and cost estimates in the plan. On December 7, 2015, Duke Energy Indiana filed a revised 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 this new statute. The revised 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 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 also provided for deferral accounting for depreciation and post-in-service carrying costs for AMI projects outside the seven-year 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 seven-year plan. In 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, based in part on Duke Energy Indiana's intent to file a base rate case in 2022 under the approved T&D Rider plan. At December 31, 2016, Duke Energy Indiana's remaining net book value of non-AMI meters is approximately $46 million which will be depreciated through 2022. In the event that Duke Energy Indiana was to file a base rate case earlier than 2022, it may incur additional impairment charges.

Other Regulatory Matters

Atlantic Coast Pipeline

On September 2, 2014, Duke Energy, Dominion Resources (Dominion), Piedmont and Southern Company Gas, formerly AGL Resources Inc., announced the formation of 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 the needs identified in RFPs by Duke Energy Carolinas, Duke Energy Progress and Piedmont. The ACP pipeline development costs are estimated between $5.0 billion to $5.5 billion. Dominion will build and operate the ACP pipeline. Originally, Dominion held a 45 percent membership interest in ACP, Duke Energy held a 40 percent interest, Piedmont held a 10 percent interest and Southern Company Gas held a 5 percent interest. On October 3, 2016, Duke Energy and Piedmont completed a merger transaction that resulted in Piedmont becoming a wholly owned subsidiary of Duke Energy. In connection with this transaction, and pursuant to terms of the ACP partnership agreement, Piedmont transferred 3 percent of its membership interest in ACP to Dominion in exchange for approximately $14 million. As a result of this transfer, Dominion maintains a leading ownership percentage in ACP of 48 percent and Duke Energy owns a 47 percent interest through its Gas Utilities and Infrastructure segment. Southern Company Gas maintains a 5 percent interest. See Note 2 for additional information related to Duke Energy's acquisition of Piedmont.

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. In October 2014, the NCUC and PSCSC approved the Duke Energy Carolinas and Duke Energy Progress requests to enter into certain affiliate agreements, pay compensation to ACP and to grant a waiver of certain Code of Conduct provisions relating to contractual and jurisdictional matters. On September 18, 2015, ACP filed an application with the FERC requesting a CPCN authorizing ACP to construct the pipeline. In December 2016, FERC issued a preliminary Environmental Impact Statement (EIS) indicating that the proposed pipeline would not cause significant harm to the environment or protected populations. The final EIS is expected by June 30, 2017. FERC approval of the application is expected within 90 days of the issuance of the final EIS. Construction is projected to begin once FERC approval is received with a targeted in-service date in the second half of 2019. ACP executed a construction agreement in September 2016 and is working with various agencies to develop the final pipeline route. ACP also requested approval of an open access tariff and the precedent agreements it entered into with future pipeline customers, including Duke Energy Carolinas and Duke Energy Progress. See Notes 12 and 17 for additional information.

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 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 that is constructing 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 will traverse 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. 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 has received regulatory approvals and initiated construction of the pipeline with an expected in-service date in mid-2017. See Notes 12 and 17 for additional information.

Constitution Pipeline

Duke Energy owns a 24 percent ownership interest in Constitution Pipeline Company, LLC (Constitution) through a wholly owned subsidiary of Piedmont. 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.

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. District Court for the Northern District of New York and 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. Both courts granted Constitution's motions to expedite the schedules for the legal actions. On November 16, 2016, oral arguments were heard in the U.S. Court of Appeals.

Constitution remains steadfastly committed to pursuing the project and intends to pursue all available options to challenge the NYSDEC's decision. In light of the denial of the certification, Constitution revised its target in-service date of the project to be as early as the second half of 2018, assuming that the challenge process is satisfactorily and promptly concluded.

In July 2016, Constitution requested and the FERC approved an extension of the construction period and in-service deadline of the project to December 2018. Also in July, the FERC denied the New York Attorney General's (NYAG) complaint and request for a stay of the certificate order authorizing the project on the grounds that Constitution had improperly cut trees along the proposed route. The FERC found the complaint procedurally deficient and that there was no justification for a stay; it did find the filing constituted a valid request for investigation and thus referred the matter to FERC staff for further examination as may be appropriate. On November 22, 2016, the FERC denied the NYAG's request for reconsideration of this order.

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. As a result, Duke Energy evaluated the investment in the Constitution project for OTTIs. At this time, no OTTI has been determined and therefore no impairment charge to reduce the carrying value of the investment has been recorded. However, to the extent that the legal and regulatory proceedings have unfavorable outcomes, or if Constitution concludes that the project is not viable or does not go forward as legal and regulatory actions progress, the conclusions with respect to OTTIs could change and may require that an impairment charge of up to the recorded investment in the project, net of any cash and working capital returned, be recorded. Duke Energy will continue to monitor and update the OTTI analysis as required. Different assumptions could affect the timing and amount of any charge recorded in a period.

Pending the outcome of the matters described above, and when construction proceeds, Duke Energy remains committed to fund an amount in proportion to its ownership interest for the development and construction of the new pipeline. Duke Energy's total anticipated contributions are approximately $229 million. See Notes 12 and 17 for additional information.

Progress Energy Merger FERC Mitigation

In June 2012, the FERC approved the merger with Progress Energy, including Duke Energy and Progress Energy’s revised market power mitigation plan, the Joint Dispatch Agreement (JDA) and the joint Open Access Transmission Tariff. The revised market power mitigation plan provided for the acceleration of one transmission project and the completion of seven other transmission projects (Long-Term FERC Mitigation) and interim firm power sale agreements during the completion of the transmission projects (Interim FERC Mitigation). The Long-Term FERC Mitigation was expected to increase power imported into the Duke Energy Carolinas and Duke Energy Progress service areas and enhance competitive power supply options in the service areas. All of these projects were completed in or before 2014. On May 30, 2014, the Independent Monitor filed with FERC a final report stating that the Long-Term FERC Mitigation is complete. In 2014, Duke Energy Progress recorded an $18 million partial reversal of an impairment recorded in 2012. This reversal adjusts the initial disallowance from the Long-Term FERC mitigation and reflects updated information on the construction costs and in-service dates of the transmission projects.

Following the closing of the merger, outside counsel reviewed Duke Energy’s 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, 2016 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	$ 168
Progress Energy and Duke Energy Florida		
Crystal River Units 1 and 2	873	120
Duke Energy Indiana[(b)]		
Gallagher Units 2 and 4[(c)]	280	136
Total Duke Energy	1,738	$ 424

(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 Indiana retired Wabash River Units 2 through 6 in 2016.

(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.

On October 23, 2015, the EPA published in the Federal Register the final Clean Power Plan (CPP) rule regulating carbon dioxide (CO_2) emissions from existing fossil fuel-fired electric generating units (EGUs). The CPP establishes CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired EGUs. Petitions challenging the final CPP have been filed by several groups and on February 9, 2016, the U.S. Supreme Court issued a stay of the final CPP rule, halting implementation until legal challenges are resolved. States in which the Duke Energy Registrants operate have suspended work on CPP compliance plans as a result of the stay. The court is expected to decide the case in early 2017. Compliance with CPP could cause the industry to replace coal-fired generation with natural gas and renewables, especially in states that have significant CO_2 reduction targets under the rule. Costs to operate coal-fired generation plants continue to grow due to increasing environmental compliance requirements, including ash management costs unrelated to CPP, which may result in the retirement of coal-fired generation plants earlier than the current end of useful lives. Duke Energy continues to evaluate the need to retire generating facilities and plans to seek regulatory recovery, where appropriate, for amounts that have not been recovered upon asset retirements. However, recovery is subject to future regulatory approval, including the recovery of carrying costs on remaining book values, and therefore cannot be assured.

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 has been retired.

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 United States 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 was $375 million per station. For incidents after January 1, 2017, this primary nuclear liability insurance limit increased to $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 "all risk" property damage, 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 some replacement power cost insurance for each station for losses in the event of a major accidental outage at an insured nuclear station. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium or other means of assurance. The companies are required each year to report to the NRC the current levels and sources of insurance that demonstrate it possesses sufficient financial resources to stabilize and decontaminate its reactors and reactor station sites in the event of an accident.

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 replacement power cost insurance 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, Catawba, Brunswick and Harris, $464 million for Oconee and $404 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 $164 million, $104 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 Other within Deferred Credits and Other 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, 2013	$ 74	$ 11	$ 27	$ 8	$ 19	$ 27	$ 7
Provisions/adjustments	32	(1)	1	4	(3)	28	4
Cash reductions	(14)	—	(11)	(7)	(4)	(1)	(1)
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**

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	**$ 69**
Duke Energy Carolinas	**22**
Duke Energy Ohio	**36**
Duke Energy Indiana	**7**

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 Energy 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 and an alternative Motion to Dismiss. On August 31, 2015, the court issued an order staying the case which was lifted on March 24, 2016. On April 22, 2016, 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. On December 14, 2016, the Delaware Chancery Court entered an order dismissing the Amended Complaint. Plaintiffs filed an appeal to the Delaware Supreme Court on January 9, 2017. Opening briefs were due by February 24, 2017, and a date for oral argument has not been set.

On March 5, 2015, shareholder Judy Mesirov filed a shareholder derivative complaint (Mesirov Complaint) in North Carolina state court. The lawsuit, styled *Mesirov v. Good*, was similar to the consolidated derivative action pending in Delaware Chancery Court and was filed against the same current directors and former directors and officers as the Delaware litigation. Duke Energy Corporation, Duke Energy Progress and Duke Energy Carolinas were named as nominal defendants. The Mesirov Complaint alleged that the Duke Energy Board of Directors was aware of Clean Water Act (CWA) compliance issues and failures to maintain structures in ash basins, but that the Board of Directors did not require Duke Energy Carolinas and Duke Energy Progress to take action to remedy deficiencies. The Mesirov Complaint further alleged that the Board of Directors sanctioned activities to avoid compliance with the law by allowing improper influence of the NCDEQ to minimize regulation and by opposing previously anticipated citizen suit litigation. The Mesirov Complaint sought corporate governance reforms and damages relating to costs associated with the Dan River release, remediation of ash basins that are out of compliance with the CWA and defending and payment of fines, penalties and settlements relating to criminal and civil investigations and lawsuits. On July 5, 2016, the plaintiff filed a Notice of Voluntary Dismissal Without Prejudice, closing this matter.

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.

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. The Bresalier Defendants filed a Motion to Dismiss the Bresalier litigation on January 15, 2016. In lieu of a response to the Motion to Dismiss, the plaintiff filed a Motion to Convert the Bresalier Defendants' Motion to Dismiss into a Motion for Summary Judgment and also for limited discovery. Following a hearing on June 15, 2016, the court denied the plaintiff's Motion to Convert and is requiring the parties to complete briefing on the Bresalier Defendants' Motion to Dismiss. On July 29, 2016, the Bresalier Defendants filed an Amended Motion to Dismiss. Oral argument on the Amended Motion to Dismiss was heard on December 20, 2016. As discussed below, an agreement-in-principle has been reached to settle the merger related claims in the Bresalier Complaint.

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

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, for a total of $27 million. The entire settlement amount is to be funded by insurance. The settlement amount, less court-approved attorney fees, will be payable to Duke Energy. The settlement is subject to the execution of definitive settlement documents and court approval.

Price Reporting Cases

Duke Energy Trading and Marketing, LLC (DETM), a non-operating Duke Energy affiliate, was a defendant, along with numerous other energy companies, in four class-action lawsuits and a fifth single-plaintiff lawsuit in a consolidated federal court proceeding in Nevada. Each of these lawsuits contained similar claims that defendants allegedly manipulated natural gas markets by various means, including providing false information to natural gas trade publications and entering into unlawful arrangements and agreements in violation of the antitrust laws of the respective states. Plaintiffs sought damages in unspecified amounts. In February 2016, DETM reached agreements in principle to settle all of the pending lawsuits. Settlement of the single-plaintiff settlement was finalized and paid in March 2016. The proposed settlement of the class-action lawsuits was submitted to the Court and preliminarily approved on January 26, 2017. The Court will consider final approval of the class settlement following notice to the class members. The settlement amounts are not material to Duke Energy.

Duke Energy Carolinas and Duke Energy Progress

NCDEQ Notice of Violation

In August 2014, NCDEQ issued an NOV for alleged groundwater violations at Duke Energy Progress' Sutton Plant. On March 10, 2015, NCDEQ issued a civil penalty of approximately $25 million to Duke Energy Progress for environmental damages related to alleged groundwater contamination at the Sutton Plant. On April 9, 2015, Duke Energy Progress filed a Petition for Contested Case hearing in the Office of Administrative Hearings. In February 2015, NCDEQ issued an NOV for alleged groundwater violations at Duke Energy Progress' Asheville Plant. Duke Energy Progress responded to NCDEQ regarding this NOV.

On September 29, 2015, Duke Energy Progress and Duke Energy Carolinas entered into a settlement agreement with NCDEQ resolving all former, current and future groundwater penalties at all Duke Energy Carolinas and Duke Energy Progress coal facilities in North Carolina. Under the agreement, Duke Energy Progress paid approximately $6 million and Duke Energy Carolinas paid approximately $1 million. In addition to these payments, Duke Energy Progress and Duke Energy Carolinas will accelerate remediation actions at the Sutton, Asheville, Belews Creek and H.F. Lee plants. The court entered a consent order resolving the contested case relating to the Sutton Plant and NCDEQ rescinded the NOVs relating to alleged groundwater violations at both the Sutton and Asheville plants.

On October 13, 2015, the Southern Environmental Law Center (SELC), representing multiple conservation groups, filed a lawsuit in North Carolina Superior Court seeking judicial review of the order approving the settlement agreement with NCDEQ. The conservation groups contend that the ALJ exceeded his statutory authority in approving a settlement that provided for past, present and future resolution of groundwater issues at facilities which were not at issue in the penalty appeal. On December 18, 2015, Duke Energy Carolinas and Duke Energy Progress filed a Motion to Dismiss the complaint. On February 12, 2016, the ALJ entered a new order clarifying that the dismissal of the contested case only applied to the specific issues before the ALJ in the Petition for Contested Case. On March 10, 2016, the court dismissed the SELC lawsuit based on the ALJ's entry of the new order.

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, SELC sent notices of intent to sue Duke Energy Carolinas and Duke Energy Progress related to alleged 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.

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.

On July 10, 2015, Duke Energy Carolinas and Duke Energy Progress filed two Motions for Partial Summary Judgment in the case on the basis that there is no longer either a genuine controversy or disputed material facts about the relief for seven of the 14 North Carolina plants with coal ash basins. On September 14, 2015, the court granted the Motions for Partial Summary Judgment pending court approval of the terms through an order. On April 4, 2016, the court issued an order granting Duke Energy Progress' Motion for Partial Summary Judgment for cases involving the H.F. Lee, Cape Fear and Weatherspoon plants. On June 1, 2016, the court issued an order granting Duke Energy Carolinas' and Duke Energy Progress' Motion for Partial Summary Judgment for cases involving the Asheville, Dan River, Riverbend and Sutton plants. The litigation is concluded for these seven plants. Litigation continues for the remaining seven plants. In response to a motion for partial summary judgment on the groundwater claims filed by the environmental groups, on October 17, 2016, Duke Energy Carolinas and Duke Energy Progress filed a cross-motion for partial summary judgment on the groundwater claims. On February 13, 2017, the court issued an order denying both the environmental groups' motion for partial summary judgment and Duke Energy Carolinas and Duke Energy Progress' cross-motion for partial summary judgment.

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 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 the complaint and a decision is pending. It is not possible to predict whether Duke Energy Progress will incur any liability or to estimate the damages, if any, they might incur in connection with this matter.

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

North Carolina Ash Basin Grand Jury Investigation

As a result of the Dan River ash basin water release discussed above, NCDEQ issued a NOV and Recommendation of Assessment of Civil Penalties with respect to this matter on February 28, 2014, which the company responded to on March 13, 2014. Duke Energy and certain Duke Energy employees received subpoenas issued by the United States Attorney for the Eastern District of North Carolina in connection with a criminal investigation related to all 14 of the North Carolina facilities with ash basins and the nature of Duke Energy's contacts with NCDEQ with respect to those facilities. This was a multidistrict investigation that also involves state law enforcement authorities.

On February 20, 2015, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Business Services LLC (DEBS), a wholly owned subsidiary of Duke Energy, each entered into Plea Agreements in connection with the investigation initiated by the United States Department of Justice Environmental Crimes Section and the United States Attorneys for the Eastern District of North Carolina, the Middle District of North Carolina and the Western District of North Carolina (collectively, USDOJ). On May 14, 2015, the United States District Court for the Eastern District of North Carolina approved the Plea Agreements.

Under the Plea Agreements, DEBS and Duke Energy Progress pleaded guilty to four misdemeanor CWA violations related to violations at Duke Energy Progress’ H.F. Lee Steam Electric Plant, Cape Fear Steam Electric Plant and Asheville Steam Electric Generating Plant. Duke Energy Carolinas and DEBS pleaded guilty to five misdemeanor CWA violations related to violations at Duke Energy Carolinas’ Dan River Steam Station and Riverbend Steam Station. DEBS, Duke Energy Carolinas and Duke Energy Progress also agreed (i) to a five-year probation period, (ii) to pay a total of approximately $68 million in fines and restitution and $34 million for community service and mitigation (the Payments), (iii) to fund and establish environmental compliance plans subject to the oversight of a court-appointed monitor in addition to certain other conditions set out in the Plea Agreements. Duke Energy Carolinas and Duke Energy Progress also agree to each maintain $250 million under their Master Credit Facility as security to meet their obligations under the Plea Agreements. Payments under the Plea Agreements will be borne by shareholders and are not tax deductible. Duke Energy Corporation has agreed to issue a guarantee of all payments and performance due from DEBS, Duke Energy Carolinas and Duke Energy Progress, including but not limited to payments for fines, restitution, community service, mitigation and the funding of, and obligations under, the environmental compliance plans. As a result of the Plea Agreements, Duke Energy Carolinas and Duke Energy Progress recognized charges of $72 million and $30 million, respectively, in Operation, maintenance and other on the Consolidated Statements of Operations and Comprehensive Income during 2014. Payment of the amounts relating to fines and restitution were made between May and July 2015. The Plea Agreements do not cover pending civil claims related to the Dan River coal ash release and operations at other North Carolina coal plants.

On May 14, 2015, Duke Energy reached an Interim Administrative Agreement with the U.S. Environmental Protection Agency Office of Suspension and Debarment that avoids debarment of DEBS, Duke Energy Carolinas or Duke Energy Progress with respect to all active generating facilities. The Interim Administrative Agreement imposes a number of requirements relating to environmental and ethical compliance, subject to the oversight of an independent monitor.

Potential 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). The criteria, in some cases, are considerably more stringent than federal drinking water standards established to protect human health and welfare. The North Carolina Coal Ash Management Act of 2014, as amended, (Coal Ash Act) requires additional groundwater monitoring and assessments for each of the 14 coal-fired plants in North Carolina, including sampling of private water supply wells. The data gathered through these Comprehensive Site Assessments (CSAs) will be used by NCDEQ to determine whether the water quality of these private water supply wells has been adversely impacted by the ash basins. Duke Energy has submitted CSAs documenting the results of extensive groundwater monitoring around coal ash basins at all 14 of the plants with coal ash basins. Generally, the data gathered through the installation of new monitoring wells and soil and water samples across the state 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 leads 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 which the plan is offered. Duke Energy Carolinas and Duke Energy Progress recognized charges of $18 million and $4 million, respectively, in Operation, maintenance and other on the Consolidated Statements of Operations and Comprehensive Income in December 2016.

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, 2016, there were 121 asserted claims for non-malignant cases with the cumulative relief sought of up to $32 million and 58 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 $512 million and $536 million at December 31, 2016 and 2015, respectively. These reserves are classified in Other within Deferred Credits and Other 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 2036, 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 2036 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 $814 million in excess of the self-insured retention. Receivables for insurance recoveries were $587 million and $599 million at December 31, 2016 and 2015, respectively. These amounts are classified in Other within Investments and Other Assets and Receivables 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. Claims for all periods prior to 2011 have been resolved. Additional claims are likely to be filed after the current litigation is resolved. Trial has been set for June 2017. Duke Energy Progress and Duke Energy Florida 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. 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.

It is not possible to predict the ultimate outcome of the appeal of the trial court's order. Ultimate resolution of these matters could have a material effect on the results of operations, financial position or cash flows of Duke Energy Florida. However, appropriate regulatory recovery will be pursued for the retail portion of any costs incurred in connection with such resolution.

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 6th Circuit. 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. See Note 2 for further discussion on the Midwest Generation Exit.

W.C. Beckjord Fuel Release

On August 18, 2014, approximately 9,000 gallons of fuel oil were inadvertently discharged into the Ohio River during a fuel oil transfer at the W.C. Beckjord generating station. The Ohio Environmental Protection Agency issued a NOV related to the discharge. On November 22, 2016, Duke Energy Ohio entered into a plea agreement with the U.S. Attorney for the Southern District of Ohio. Terms of the agreement include a misdemeanor violation of the CWA, a fine of $1 million and a $100 thousand contribution to the Foundation for Ohio River Education, which were paid in fourth quarter 2016. Duke Energy Ohio has also reimbursed government and private entities for approximately $1 million of costs incurred as a result of the fuel release.

Duke Energy Indiana

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 totaling approximately $16 million 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 is 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. The matter has been remanded to a lower court to determine damages. Duke Energy Indiana cannot predict the outcome of this matter. Ultimate resolution of this matter could have a material effect on the results of operations, financial position or cash flows of Duke Energy Indiana. However, appropriate regulatory recovery will be pursued for the retail portion of any costs incurred in connection with such resolution.

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 Deferred Credits and Other 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)	2016	2015
Reserves for Legal Matters		
Duke Energy	**$ 98**	$ 156
Duke Energy Carolinas	**23**	11
Progress Energy	**59**	54
Duke Energy Progress	**14**	6
Duke Energy Florida	**28**	31
Duke Energy Ohio	**4**	80

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.

		Minimum Purchase Amount at December 31, 2016						
(in millions)	Contract Expiration	2017	2018	2019	2020	2021	Thereafter	Total
Duke Energy Progress[a]	2019-2031	$ 66	$ 67	$ 67	$ 50	$ 51	$ 267	$ 568
Duke Energy Florida[b]	2021-2043	341	357	377	394	376	1,211	3,056
Duke Energy Ohio[c][d]	2018	203	89	—	—	—	—	292

(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.
(c) Contracts represent between 1 percent and 11 percent of net plant output.
(d) Excludes PPA with OVEC. See Note 17 for additional information.

Gas Supply and Capacity Contracts

Duke Energy and Duke Energy Ohio routinely enter into long-term 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, 2016.

(in millions)	Duke Energy	Duke Energy Ohio
2017	$ 371	$ 52
2018	308	35
2019	286	26
2020	269	22
2021	267	22
Thereafter	1,595	7
Total	$ 3,096	$ 164

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 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 table presents 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)	2016	2015	2014
Duke Energy	$ 242	$ 313	$ 350
Duke Energy Carolinas	45	41	41
Progress Energy	140	230	257
Duke Energy Progress	68	149	161
Duke Energy Florida	72	81	96
Duke Energy Ohio	16	13	17
Duke Energy Indiana	23	20	21

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, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
2017	$ 218	$ 41	$ 129	$ 75	$ 54	$ 12	$ 20
2018	205	35	126	73	53	11	17
2019	181	27	120	68	52	7	11
2020	164	23	109	58	51	6	10
2021	134	17	91	43	48	4	6
Thereafter	948	52	602	379	223	7	9
Total	$ 1,850	$ 195	$ 1,177	$ 696	$ 481	$ 47	$ 73

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

	December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
2017	$ 148	$ 6	$ 46	$ 21	$ 25	$ 4	$ 1
2018	154	6	46	21	25	3	2
2019	154	6	45	20	25	1	1
2020	159	5	46	22	25	—	1
2021	163	1	45	20	25	—	1
Thereafter	784	30	322	250	71	—	41
Minimum annual payments	1,562	54	550	354	196	8	47
Less: amount representing interest	(462)	(32)	(265)	(212)	(53)	(1)	(36)
Total	$ 1,100	$ 22	$ 285	$ 142	$ 143	$ 7	$ 11

6. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	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**
Unsecured debt, maturing 2017 - 2073	4.30%	$ 17,812	$ 1,150	$ 3,551	$ —	$ 150	$ 810	$ 415
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)
Unamortized debt issuance costs(g)		(242)	(45)	(104)	(38)	(52)	(7)	(22)
Total debt	4.07%	$ 50,382	$ 9,603	$ 18,270	$ 7,011	$ 6,422	$ 1,900	$ 3,786
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)
Total long-term debt(h)		$ 45,576	$ 9,487	$ 16,763	$ 6,559	$ 5,799	$ 1,883	$ 3,783

(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 in purchase accounting adjustments related to 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.

	December 31, 2015							
(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**
Unsecured debt, maturing 2016 - 2073	4.68%	$ 12,960	$ 1,152	$ 3,850	$ —	$ 150	$ 765	$ 740
Secured debt, maturing 2016 - 2037	2.37%	2,361	425	479	254	225	—	—
First mortgage bonds, maturing 2016 - 2045[a]	4.74%	18,980	6,161	9,750	5,975	3,775	750	2,319
Capital leases, maturing 2016 - 2051[b]	5.39%	1,335	24	300	144	156	13	14
Tax-exempt bonds, maturing 2017 - 2041[c]	2.59%	1,053	355	48	48	—	77	572
Notes payable and commercial paper[d]	0.88%	4,258	—	—	—	—	—	—
Money pool/intercompany borrowings		—	300	1,458	359	813	128	150
Fair value hedge carrying value adjustment		6	6	—	—	—	—	—
Unamortized debt discount and premium, net[e]		1,712	(17)	(28)	(16)	(8)	(28)	(8)
Unamortized debt issuance costs[f]		(164)	(39)	(85)	(37)	(32)	(4)	(19)
Total debt	4.15%	$ 42,501	$ 8,367	$ 15,772	$ 6,727	$ 5,079	$ 1,701	$ 3,768
Short-term notes payable and commercial paper		(3,633)	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	—	(1,308)	(209)	(813)	(103)	—
Current maturities of long-term debt[g]		(2,026)	(356)	(315)	(2)	(13)	(106)	(547)
Total long-term debt[g]		$ 36,842	$ 8,011	$ 14,149	$ 6,516	$ 4,253	$ 1,492	$ 3,221

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $114 million and $731 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 commercial paper was 15 days.
(e) Duke Energy includes $1,798 million in purchase accounting adjustments related to the merger with Progress Energy.
(f) Duke Energy includes $59 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.

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, 2016
Unsecured Debt			
Duke Energy (Parent)	April 2017	1.226%	$ **400**
Duke Energy (Parent)	August 2017	1.625%	**700**
Piedmont Natural Gas	September 2017	8.510%	**35**
First Mortgage Bonds			
Duke Energy Progress	March 2017	1.146%	**250**
Duke Energy Florida	September 2017	5.800%	**250**
Duke Energy Progress	November 2017	1.111%	**200**
Secured			
Duke Energy	June 2017	2.365%	**45**
Duke Energy	June 2017	2.260%	**34**
Tax-exempt Bonds			
Duke Energy Carolinas	February 2017	3.600%	**77**
Duke Energy Carolinas	February 2017	0.810%	**10**
Duke Energy Carolinas	February 2017	0.790%	**25**
Other[(a)]			**293**
Current maturities of long-term debt			$ **2,319**

(a) Includes capital lease obligations, amortizing debt and small bullet maturities.

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, 2016						
(in millions)	Duke Energy[(a)]	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
2017	$ 2,319	$ 116	$ 778	$ 452	$ 326	$ 1	$ 3
2018	3,466	1,629	559	—	561	3	3
2019	3,316	5	1,992	902	292	551	63
2020	2,112	755	469	152	319	25	653
2021	3,699	501	1,473	602	372	49	70
Thereafter	31,090	6,597	12,270	4,903	4,255	1,255	2,994
Total long-term debt, including current maturities	$ 46,002	$ 9,603	$ 17,541	$ 7,011	$ 6,125	$ 1,884	$ 3,786

(a) Excludes $1,893 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, 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**

	December 31, 2015				
(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

Piedmont Acquisition Financing

In August 2016, Duke Energy issued $3.75 billion of senior unsecured notes in three separate series. The net 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.

Nuclear Asset-Recovery Bonds

In June 2016, DEFPF issued $1,294 million of 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. See Notes 4 and 17 for additional information.

Solar Facilities Financing

In August 2016, Emerald State Solar, LLC, an indirect wholly owned subsidiary of Duke Energy, entered into a $333 million portfolio financing of approximately 22 North Carolina Solar facilities. Tranche A of $228 million is secured by substantially all 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.

Duke Energy Florida Bond Issuance

In January 2017, Duke Energy Florida issued $900 million of first mortgage bonds. The issuance was split between a $250 million, three-year series and a $650 million, 10-year series. The net proceeds from the issuance were used to repay at maturity $250 million aggregate principal amount of bonds due September 2017, as well as to fund capital expenditures for ongoing construction and capital maintenance and for general corporate purposes.

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

			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	September 2021	1.800%	750	750	—	—	—	—	—
August 2016	September 2026	2.650%	1,500	1,500	—	—	—	—	—
August 2016	September 2046	3.750%	1,500	1,500	—	—	—	—	—
Secured Debt									
June 2016[(b)]	March 2020	1.196%	183	—	—	—	183	—	—
June 2016[(b)]	September 2022	1.731%	150	—	—	—	150	—	—
June 2016[(b)]	September 2029	2.538%	436	—	—	—	436	—	—
June 2016[(b)]	March 2033	2.858%	250	—	—	—	250	—	—
June 2016[(b)]	September 2036	3.112%	275	—	—	—	275	—	—
August 2016	June 2034	2.747%	228	—	—	—	—	—	—
August 2016	June 2020	2.747%	105	—	—	—	—	—	—
First Mortgage Bonds									
March 2016[(c)]	March 2023	2.500%	500	—	500	—	—	—	—
March 2016[(c)]	March 2046	3.875%	500	—	500	—	—	—	—
May 2016[(d)]	May 2046	3.750%	500	—	—	—	—	—	500
June 2016[(c)]	June 2046	3.700%	250	—	—	—	—	250	—
September 2016[(e)]	October 2046	3.400%	600	—	—	—	600	—	—
September 2016[(c)]	October 2046	3.700%	450	—	—	450	—	—	—
November 2016[(f)]	December 2026	2.950%	600	—	600	—	—	—	—
Total issuances			$ 9,127	$ 4,100	$ 1,600	$ 450	$ 1,894	$ 250	$ 500

(a) Proceeds were used to pay down outstanding commercial paper and for general corporate purposes.
(b) The nuclear asset recovery bonds are sequential pay amortizing bonds. The maturity date above represents the scheduled final maturity date for the bonds.
(c) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance and for general corporate purposes.
(d) 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.
(e) 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.
(f) 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.

			Year Ended December 31, 2015			
Issuance Date	**Maturity Date**	**Interest Rate**	**Duke Energy**	**Duke Energy (Parent)**	**Duke Energy Carolinas**	**Duke Energy Progress**
Unsecured Debt						
November 2015(a)(b)	April 2024	3.750%	$ 400	$ 400	$ —	$ —
November 2015(a)(b)	December 2045	4.800%	600	600	—	—
First Mortgage Bonds						
March 2015(c)	June 2045	3.750%	500	—	500	—
August 2015(a)(d)	August 2025	3.250%	500	—	—	500
August 2015(a)(d)	August 2045	4.200%	700	—	—	700
Total issuances			$ 2,700	$ 1,000	$ 500	$ 1,200

(a) Proceeds were used to repay short-term money pool and commercial paper borrowing issued to fund a portion of the NCEMPA acquisition, see Note 2 for further information.
(b) Proceeds were used to refinance at maturity $300 million of unsecured notes at Progress Energy due January 2016.
(c) Proceeds were used to redeem at maturity $500 million of first mortgage bonds due October 2015.
(d) Proceeds were used to refinance at maturity $400 million of first mortgage bonds due December 2015.

Available Credit Facilities

Duke Energy has a Master Credit Facility with a capacity of $7.5 billion through January 2020. The Duke Energy Registrants, excluding Progress Energy (Parent) and Piedmont, 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.

Piedmont has a separate five-year revolving syndicated credit facility, with a capacity of $850 million through December 2020 and an expansion option of up to an additional $200 million. The facility provides a line of credit for letters of credit of $10 million.

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

	December 31, 2016						
(in millions)	**Duke Energy[a]**	**Duke Energy (Parent)**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Facility size[b]	**$ 8,350**	**$ 3,400**	**$ 1,100**	**$ 1,000**	**$ 950**	**$ 450**	**$ 600**
Reduction to backstop issuances							
Commercial paper[c]	**(2,022)**	**(977)**	**(300)**	**(150)**	**(84)**	**(31)**	**(150)**
Outstanding letters of credit	**(78)**	**(69)**	**(4)**	**(2)**	**(1)**	**—**	**—**
Tax-exempt bonds	**(116)**	**—**	**(35)**	**—**	**—**	**—**	**(81)**
Coal ash set-aside	**(500)**	**—**	**(250)**	**(250)**	**—**	**—**	**—**
Available capacity	**$ 5,634**	**$ 2,354**	**$ 511**	**$ 598**	**$ 865**	**$ 419**	**$ 369**

(a) Includes amounts related to Piedmont's $850 million credit facility.
(b) Represents the sublimit of each borrower.
(c) 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.

Term Loan Facility

In 2016, Duke Energy (Parent) entered into a $1.5 billion term loan facility, as amended (Term Loan) maturing on July 31, 2017. During 2016, Duke Energy (Parent) drew the full amount available under the Term Loan and used $750 million of proceeds to fund a portion of the Piedmont acquisition and the remaining $750 million to manage short-term liquidity and for general corporate purposes. The terms and conditions of the Term Loan are generally consistent with those governing Duke Energy’s Master Credit Facility. In December 2016, Duke Energy (Parent) repaid the $1.5 billion term loan which terminated this 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, 2016 and 2015 was $1,090 million and $1,121 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 $762 million and $767 million, respectively, as of December 31, 2016 and 2015.

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. Piedmont's credit facility contains a debt-to-total capitalization ratio covenant not to exceed 70 percent. 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, 2016, each of the Duke Energy Registrants were 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, 2016 and 2015, Duke Energy had loans outstanding of $661 million, including $39 million at Duke Energy Progress and $629 million, including $41 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, 2016, 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, 2016, 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, 2016, was $333 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, $215 million of the guarantees expire between 2017 and 2033, with the remaining performance guarantees having no contractual expiration.

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, 2016, Duke Energy had guaranteed $44 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 which 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, 2016, Duke Energy had issued a total of $485 million in letters of credit, which expire between 2017 and 2020. The unused amount under these letters of credit was $77 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, 2016, the estimated maximum exposure for these indemnifications was $96 million, the majority of which expires in 2017. Of this amount, $7 million has no contractual 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.

The following table includes the liabilities recognized for the guarantees discussed above. These amounts are primarily recorded in Other within Deferred Credits and other Liabilities on the Consolidated Balance Sheets. 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.

	December 31,	
(in millions)	**2016**	**2015**
Duke Energy	**$ 13**	$ 21
Progress Energy	**—**	7
Duke Energy Florida	**—**	7

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, 2016			
(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%**	**$ 954**	**$ 612**	**$ 12**
Duke Energy Ohio				
Transmission facilities[(b)]	**Various**	**90**	**60**	**1**
Duke Energy Indiana				
Gibson Station (unit 5)[(c)]	**50.05%**	**333**	**157**	**11**
Vermillion Generating Station[(d)]	**62.5%**	**154**	**111**	**—**
Transmission and local facilities[(c)]	**Various**	**4,315**	**1,715**	**—**

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

On August 31, 2016, Duke Energy Florida completed the purchase of Georgia Power Company's (GPC) ownership interest in Intercession City Station Unit 11 for an amount equal to GPC's net book value of the facility as of the transaction close date. Following the purchase, Duke Energy Florida controls the entire output of the facility.

At December 31, 2016, Duke Energy Florida owns 100 percent of the retired Crystal River Unit 3. Duke Energy Florida completed the purchase of 1.7 percent ownership interest from Seminole Electric Cooperative, Inc. on November 30, 2016. On October 30, 2015, Duke Energy Florida completed the purchase of 6.52 percent ownership interest from the Florida Municipal Joint Owners and settled other disputes for $55 million. All costs associated with Crystal River Unit 3 are included within Regulatory assets on the Consolidated Balance Sheets of Duke Energy, Progress Energy and Duke Energy Florida. See Note 4 for additional information.

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, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Decommissioning of Nuclear Power Facilities[(a)]	$ 5,204	$ 1,834	$ 3,172	$ 2,454	$ 717	$ —	$ —
Closure of Ash Impoundments	5,150	2,032	2,228	2,209	19	43	847
Other[(b)]	257	29	75	34	42	34	19
Total asset retirement obligation	$ 10,611	$ 3,895	$ 5,475	$ 4,697	$ 778	$ 77	$ 866
Less: current portion	411	222	189	189	—	—	—
Total noncurrent asset retirement obligation	$ 10,200	$ 3,673	$ 5,286	$ 4,508	$ 778	$ 77	$ 866

(a) The Duke Energy amount includes purchase accounting adjustments related to the merger with Progress Energy.

(b) Primarily includes obligations related to asbestos removal and the closure of certain landfills at fossil generation facilities. Duke Energy Ohio also includes AROs related to the retirement of natural gas mains and services. Duke Energy includes AROs related to the removal of renewable energy generation assets and Piedmont's underground natural gas mains and services.

North Carolina Ash Basins

AROs recorded on the Duke Energy Carolinas and Duke Energy Progress Consolidated Balance Sheets include the legal obligation for closure of coal ash basins and the disposal of related ash as a result of the Coal Ash Act, the EPA CCR rule and other agreements.

In 2014 the Coal Ash Act became law and was amended on June 24, 2015, and July 14, 2016. The Coal Ash Act, as amended,

- Prohibits construction of new and expansion of existing ash impoundments and use of existing impoundments at retired facilities;
- Requires ash impoundments in North Carolina to be categorized as high risk, intermediate risk or low risk by the NCDEQ with the method of closure and timing to be based upon the assigned risk, with closure no later than December 31, 2029 (see below for category descriptions);
- Classifies Duke Energy Progress' Asheville and Sutton plants and Duke Energy Carolinas' Riverbend and Dan River stations as high risk;
- Requires dry disposal of fly ash at active plants, excluding the Asheville Plant, not retired by December 31, 2018;
- Requires dry disposal of bottom ash at active plants, excluding the Asheville Plant, by December 31, 2019, or retirement of active plants;
- Establishes requirements to deal with groundwater and surface water impacts from impoundments; and
- Increases the level of regulation for structural fills utilizing coal ash.

High risk basins (Asheville, Sutton, Riverbend and Dan River) require closure through excavation, including a combination of transferring the ash to an appropriate engineered landfill or conversion of the ash for beneficial use. Closure of high risk basins is required to be completed no later than August 1, 2019, except for Asheville which is required to be completed no later than August 1, 2022.

Intermediate risk basins require closure through excavation including a combination of converting the basin to a lined industrial landfill, transferring of the ash to an appropriate engineered landfill or conversion of the ash for beneficial use. Closure of intermediate risk basins is required to be completed no later than December 31, 2024, except for H.F. Lee, Cape Fear and Weatherspoon to be completed no later than August 1, 2028.

Low risk basins require closure through either the combination of the installation and maintenance of a cap system and groundwater monitoring system designed to minimize infiltration and erosion or other closure options available to intermediate risk basins. Closure of low risk basins is required to be completed no later than December 31, 2029.

In January 2016, the NCDEQ published draft risk classifications for sites not specifically delineated by the Coal Ash Act as high risk. These risk rankings were generally determined based on three primary criteria: structural integrity of the impoundments and impacts to surface water and to groundwater. The NCDEQ's draft proposed classifications categorized 12 basins at four sites as intermediate risk and four basins at three sites as low risk. The NCDEQ's draft proposed classifications also categorized nine basins at six sites as “low-to-intermediate” risk, thereby not assigning a definitive risk ranking at that time. On May 18, 2016, the NCDEQ issued new proposed risk classifications, proposing to rank all originally proposed low risk and "low-to-intermediate" risk sites as intermediate.

On July 14, 2016, the former governor of North Carolina signed legislation which amended the Coal Ash Act and required Duke Energy to undertake dam improvement projects and to provide access to a permanent alternative drinking water source to certain residents within a half mile of coal ash basin compliance boundaries and to certain other potentially impacted residents. The new legislation also ranks basins at the H.F. Lee, Cape Fear and Weatherspoon stations as intermediate risk consistent with Duke Energy's previously announced plans to excavate those basins. These specific intermediate basins require closure through excavation including a combination of transferring ash to an appropriate engineered landfill or conversion of the ash for beneficial use. Closure of these specific intermediate basins is required to be completed no later than August 1, 2028. Upon satisfactory completion of the dam improvement projects and installation of alternative drinking water sources by October 15, 2018, the legislation requires the NCDEQ to reclassify sites proposed as intermediate risk, excluding H.F. Lee, Cape Fear and Weatherspoon, as low risk. In January 2017, NCDEQ issued preliminary approval of Duke Energy's plans for the alternative water sources.

Per the Coal Ash Act, final proposed classifications were to be subject to Coal Ash Management Commission (Coal Ash Commission) approval. In March 2016, the Coal Ash Commission created by the Coal Ash Act was disbanded by the former governor of North Carolina based on a North Carolina Supreme Court ruling regarding the constitutionality of the body. The July 2016 legislation eliminates the Coal Ash Commission and transfers responsibility for ash basin closure oversight to the NCDEQ.

Additionally, the July 2016 legislation requires the installation and operation of three large-scale coal ash beneficiation projects which are expected to produce reprocessed ash for use in the concrete industry. Closure of basins at sites with these beneficiation projects are required to be completed no later than December 31, 2029. On October 5, 2016, Duke Energy announced Buck Steam Station as a first location for one of the beneficiation projects. On December 13, 2016, Duke Energy announced H.F. Lee as the second location. Duke Energy intends to announce the third location by July 1, 2017.

The Coal Ash Act includes a variance procedure for compliance deadlines and other issues surrounding the management of CCR and CCR surface impoundments. Provisions of the Coal Ash Act prohibit 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. Consistent with the requirements of the Coal Ash Act, Duke Energy has submitted CSAs and groundwater corrective action plans to NCDEQ and will submit to NCDEQ site-specific coal ash impoundment closure plans in advance of closure. These plans and all associated permits must be approved by NCDEQ before any closure work can begin.

Federal Coal Combustion Residuals Regulation

In April 2015, the EPA published a rule to regulate the disposal of CCR from electric utilities as solid waste. The federal regulation classifies CCR as nonhazardous waste and allows for beneficial use of CCR with some restrictions. The regulation applies to all new and existing landfills, new and existing surface impoundments receiving CCR and existing surface impoundments that are no longer receiving CCR but contain liquid located at stations currently generating electricity (regardless of fuel source). The 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. As a result of the EPA rule, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Ohio and Duke Energy Indiana recorded additional ARO amounts during 2015.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by most states.

In September 2014, Duke Energy Carolinas executed a consent agreement with the South Carolina Department of Health and Environmental Control (SCDHEC) requiring the excavation of an inactive ash basin and ash fill area at the W.S. Lee Steam Station. As part of this agreement, in December 2014, Duke Energy Carolinas filed an ash removal plan and schedule with SCDHEC. In April 2015, the federal CCR rules were published and Duke Energy Carolinas subsequently executed an agreement with the conservation groups Upstate Forever and Save Our Saluda that requires Duke Energy Carolinas to remediate all active and inactive ash storage areas at the W.S. Lee Steam Station. Coal-fired generation at W.S. Lee ceased in 2014 and unit 3 was converted to natural gas in March 2015. In July 2015, Duke Energy Progress executed a consent agreement with the SCDHEC requiring the excavation of an inactive ash fill area at the Robinson Plant within eight years. Coal ash impoundments at the Robinson Plant and W.S. Lee Station sites are required to be closed pursuant to the CCR rule and the provisions of these consent agreements are consistent with the federal CCR closure requirements.

Coal Ash Liability

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 the 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. 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 about revisions made to the coal ash liability during 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.

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 presented in dollars of 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 the 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. Therefore, 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.

	December 31,	
(in millions)	**2016**	**2015**
Duke Energy	**$ 5,099**	$ 4,670
Duke Energy Carolinas	**2,882**	2,686
Duke Energy Progress	**2,217**	1,984

See Note 16 for additional information related to the fair value of the Duke Energy Registrants' NDTFs.

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. Refer to Note 4 for further information on the Crystal River Unit 3 decommissioning activity and transition to SAFSTOR.

ARO Liability Rollforward

During 2016, the Duke Energy Registrants updated coal ash ARO liability estimates based on additional site-specific information about 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 table presents 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, 2014	$ 8,464	$ 3,428	$ 4,711	$ 3,905	$ 806	$ 27	$ 32
Acquisitions[(a)]	226	—	226	204	23	—	—
Accretion expense[(b)]	380	165	203	169	34	4	15
Liabilities settled[(c)]	(422)	(200)	(195)	(125)	(70)	(4)	(23)
Liabilities incurred in the current year[(d)]	1,016	178	282	282	—	116	418
Revisions in estimates of cash flows	585	347	142	132	9	(18)	83
Balance at December 31, 2015	10,249	3,918	5,369	4,567	802	125	525
Acquisitions	**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**

(a) Duke Energy Progress amount relates to the NCEMPA acquisition. See Note 2 for additional information.
(b) Substantially all accretion expense for the years ended December 31, 2016 and 2015 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 the EPA's rule for disposal of CCR.

10. PROPERTY, PLANT AND EQUIPMENT

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

	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
Land		$ 1,501	$ 432	$ 735	$ 393	$ 342	$ 150	$ 106
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	—
Other buildings and improvements	15 - 100	1,692	502	634	293	341	211	197
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
Construction in process		6,186	2,324	2,708	1,329	1,379	206	396
Other	5 - 40	4,184	904	1,206	863	332	172	226
Total property, plant and equipment(a)(d)		121,397	41,127	44,864	28,419	16,434	8,126	14,241
Total accumulated depreciation – regulated(b)(c)(d)		(37,831)	(14,365)	(15,212)	(10,561)	(4,644)	(2,579)	(4,317)
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

(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.

	December 31, 2015							
(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**
Land		$ 1,391	$ 407	$ 719	$ 392	$ 327	$ 118	$ 108
Plant – Regulated								
Electric generation, distribution and transmission	8 - 100	87,593	33,623	36,422	22,888	13,534	4,429	13,118
Natural gas transmission and distribution	12 - 67	2,322	—	—	—	—	2,322	—
Other buildings and improvements	15 - 100	1,480	477	621	294	322	204	179
Plant – Nonregulated								
Electric generation, distribution and transmission	1 - 30	3,348	—	—	—	—	—	—
Other buildings and improvements	25 - 35	410	—	—	—	—	—	—
Nuclear fuel		3,194	1,827	1,367	1,367	—	—	—
Equipment	3 - 38	1,736	368	530	398	132	344	173
Construction in process		4,485	1,860	1,827	1,118	709	180	214
Other	5 - 60	4,008	836	1,180	856	319	153	215
Total property, plant and equipment(a)(d)		109,967	39,398	42,666	27,313	15,343	7,750	14,007
Total accumulated depreciation – regulated(b)(c)(d)		(35,367)	(13,521)	(14,867)	(10,141)	(4,720)	(2,507)	(4,484)
Total accumulated depreciation – nonregulated(c)(d)		(1,369)	—	—	—	—	—	—
Generation facilities to be retired, net		548	—	548	548	—	—	—
Total net property, plant and equipment		$ 73,779	$ 25,877	$ 28,347	$ 17,720	$ 10,623	$ 5,243	$ 9,523

(a) Includes capitalized leases of $1,465 million, $40 million, $302 million, $144 million, $158 million, $96 million and $39 million at Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana, respectively, primarily in regulated plant. The Progress Energy, Duke Energy Progress and Duke Energy Florida amounts are net of $85 million, $7 million and $78 million, respectively, of accumulated amortization of capitalized leases.

(b) Includes $1,621 million, $976 million, $645 million and $645 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 $57 million, $11 million, $27 million and $7 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 $2,033 million and accumulated depreciation of consolidated VIEs of $327 million at Duke Energy.

The following table presents capitalized interest, which includes the debt component of AFUDC.

	Years Ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Duke Energy	**$ 100**	$ 98	$ 75
Duke Energy Carolinas	**38**	38	38
Progress Energy	**31**	24	11
Duke Energy Progress	**17**	20	10
Duke Energy Florida	**14**	4	1
Duke Energy Ohio	**8**	10	10
Duke Energy Indiana	**7**	6	6

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 $216 million, $172 million and $164 million for the years ended December 31, 2016, 2015 and 2014. As of December 31, 2016, renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,127 million and accumulated depreciation of $347 million. These assets are principally classified as nonregulated electric generation and transmission assets.

11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The following table presents goodwill by reportable operating segment for Duke Energy.

Duke Energy

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
Goodwill at December 31, 2015	$ 15,656	$ 294	$ 122	$ 16,072
Piedmont Acquisition[(a)]	**1,723**	**1,630**	**—**	**3,353**
Goodwill at December 31, 2016	**$ 17,379**	**$ 1,924**	**$ 122**	**$ 19,425**

(a) Refer to Note 2 for more information on the purchase accounting related to the acquisition of Piedmont.

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, 2016 and 2015.

Progress Energy

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

Impairment Testing

Duke Energy, Duke Energy Ohio and Progress Energy perform annual goodwill impairment tests each year as of August 31. Duke Energy, Duke Energy Ohio and Progress Energy 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. As the fair value of Duke Energy, Duke Energy Ohio and Progress Energy's reporting units exceeded their respective carrying values at the date of the annual impairment analysis, no impairment charges were recorded.

Intangible Assets

The following tables show the carrying amount and accumulated amortization of intangible assets included in Other within Investments and Other Assets on the Consolidated Balance Sheets of the Duke Energy Registrants at December 31, 2016 and 2015.

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

	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Emission allowances	$ 20	$ 1	$ 6	$ 2	$ 4	$ —	$ 14
Renewable energy certificates	116	30	80	80	—	5	—
Gas, coal and power contracts	24	—	—	—	—	—	24
Renewable operating and development projects	115	—	—	—	—	—	—
Other	2	—	—	—	—	—	—
Total gross carrying amounts	277	31	86	82	4	5	38
Accumulated amortization – gas, coal and power contracts	(16)	—	—	—	—	—	(16)
Accumulated amortization – renewable operating and development projects	(18)	—	—	—	—	—	—
Accumulated amortization – other	(1)	—	—	—	—	—	—
Total accumulated amortization	(35)	—	—	—	—	—	(16)
Total intangible assets, net	$ 242	$ 31	$ 86	$ 82	$ 4	$ 5	$ 22

Amortization Expense

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

	December 31,		
(in millions)	2016	2015	2014
Duke Energy	**$ 6**	$ 5	$ 6
Duke Energy Ohio	**—**	—	2
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, 2016. The expected amortization expense includes estimates of emission allowances consumption and estimates of consumption of commodities such as 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)	2017	2018	2019	2020	2021
Duke Energy	$ 5	$ 5	$ 5	$ 5	$ 5
Duke Energy Indiana	2	2	2	2	2

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. As of December 31, 2016, the carrying amount of investments in affiliates with carrying amounts greater than zero exceeded the underlying investment by $24 million. These differences are attributable to intangibles associated with underlying contracts which are reflected in the investments balance and the equity in earnings reported in the table below.

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,				
	2016		2015		2014
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Equity in earnings
Electric Utilities and Infrastructure	**$ 93**	**$ 5**	$ 57	$ (2)	$ (1)
Gas Utilities and Infrastructure	**566**	**19**	113	1	—
Commercial Renewables	**185**	**(82)**	265	(6)	8
Other	**81**	**43**	64	76	123
Total	**$ 925**	**$ (15)**	$ 499	$ 69	$ 130

During the years ended December 31, 2016, 2015 and 2014, Duke Energy received distributions from equity investments of $31 million, $104 million and $154 million, respectively, which are included in Other assets within Cash Flows from Operating 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. See Notes 4 and 17 for more information.

		Investment Amount (in millions)	
Entity Name	Ownership Interest	December 31, 2016	December 31, 2015
Pipeline Investments			
Atlantic Coast Pipeline, LLC	47%	**$ 265**	$ 52
Sabal Trail Transmission, LLC	7.5%	**140**	61
Constitution Pipeline, LLC	24%	**82**	—
Cardinal Pipeline Company, LLC	21.49%	**16**	—
Storage Facilities			
Pine Needle LNG Company, LLC	45%	**16**	—
Hardy Storage Company, LLC	50%	**47**	—
Total Investments		**$ 566**	**$ 113**

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

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 25 percent indirect interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia. Duke Energy's economic ownership interest will decrease to 17.5 percent upon successful startup of NMC's polyacetal production facility, which is expected to occur in the second quarter of 2017. Duke Energy will retain 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)	**2016**	**2015**	**2014**
Duke Energy Carolinas			
Corporate governance and shared service expenses(a)	**$ 831**	$ 914	$ 851
Indemnification coverages(b)	**22**	24	21
JDA revenue(c)	**38**	51	133
JDA expense(c)	**156**	183	198
Progress Energy			
Corporate governance and shared service expenses(a)	**$ 710**	$ 712	$ 732
Indemnification coverages(b)	**35**	38	33
JDA revenue(c)	**156**	183	198
JDA expense(c)	**38**	51	133
Intercompany natural gas purchases(d)	**19**	—	—
Duke Energy Progress			
Corporate governance and shared service expenses(a)	**$ 397**	$ 403	$ 386
Indemnification coverages(b)	**14**	16	17
JDA revenue(c)	**156**	183	198
JDA expense(c)	**38**	51	133
Intercompany natural gas purchases(d)	**19**	—	—
Duke Energy Florida			
Corporate governance and shared service expenses(a)	**$ 313**	$ 309	$ 346
Indemnification coverages(b)	**21**	22	16
Duke Energy Ohio			
Corporate governance and shared service expenses(a)	**$ 356**	$ 342	$ 316
Indemnification coverages(b)	**5**	6	13
Duke Energy Indiana			
Corporate governance and shared service expenses(a)	**$ 366**	$ 349	$ 384
Indemnification coverages(b)	**8**	9	11

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

(b) 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.

(c) 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 under the JDA are recorded in Operating Revenues on the Consolidated Statements of Operations and Comprehensive Income. Expenses from the purchase of power under the JDA are recorded in Fuel used in electric generation and purchased power on the Consolidated Statements of Operations and Comprehensive Income.

(d) Duke Energy Progress purchases natural gas from Piedmont to supply electric generation facilities. These expenses are recorded in Fuel used in electric generation and purchased power on the Consolidated Statements of Operations and Comprehensive Income.

In addition to the amounts presented above, the Subsidiary Registrants record the impact on net income of 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. The net impact of these transactions was not material for the years ended December 31, 2016, 2015 and 2014 for the Subsidiary Registrants.

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.

Duke Energy Ohio's nonregulated indirect subsidiary, Duke Energy Commercial Asset Management, LLC (DECAM), owned generating plants included in the Midwest Generation Disposal Group sold to Dynegy on April 2, 2015. On April 1, 2015, Duke Energy Ohio distributed its indirect ownership interest in DECAM to a Duke Energy subsidiary and non-cash settled DECAM's intercompany loan payable of $294 million.

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

Intercompany Income Taxes

Duke Energy and its subsidiaries 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 for the subsidiary registrants.

(in millions)	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
December 31, 2016						
Intercompany income tax receivable	**$ 1**	**$ —**	**$ —**	**$ 37**	**$ —**	**$ —**
Intercompany income tax payable	**—**	**37**	**90**	**—**	**1**	**3**
December 31, 2015						
Intercompany income tax receivable	$ 122	$ 120	$ 104	$ —	$ 54	$ —
Intercompany income tax payable	—	—	—	96	—	47

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. 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, 2016 and 2015. 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, 2016					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke 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**

	December 31, 2015					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**
Cash flow hedges[a]	$ 497	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	1,827	400	500	250	250	27
Total notional amount	$ 2,324	$ 400	$ 500	$ 250	$ 250	$ 27

(a) Duke Energy includes amounts related to consolidated VIEs of $750 million and $497 million at December 31, 2016 and 2015, respectively. The December 31, 2016, amount includes interest rate swaps related to solar facilities financing with an outstanding notional amount of $300 million, including $81 million of four-year swaps and $219 million of 18-year swaps. 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. 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, but not for speculative trading. 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, 2016						
	Duke Energy	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Electricity (gigawatt-hours)	**147**	**—**	**—**	**—**	**—**	**—**	**147**
Natural gas (millions of dekatherms)[(a)]	**890**	**91**	**269**	**118**	**151**	**—**	**1**

(a) Amounts at Duke Energy increased 529 million dekatherms due to the acquisition of Piedmont in 2016.

	December 31, 2015						
	Duke Energy	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Electricity (gigawatt-hours)	70	—	—	—	—	34	36
Natural gas (millions of dekatherms)	398	66	332	117	215	—	—

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, 2016**						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Commodity Contracts							
Not Designated as Hedging Instruments							
Current	$ 108	$ 23	$ 61	$ 35	$ 26	$ 4	$ 16
Noncurrent	32	10	21	10	11	1	—
Total Derivative Assets – Commodity Contracts	$ 140	$ 33	$ 82	$ 45	$ 37	$ 5	$ 16
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

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
Commodity Contracts							
Not Designated as Hedging Instruments							
Current	$ 43	$ —	$ 12	$ —	$ 12	$ —	$ 2
Noncurrent	166	1	7	1	—	—	—
Total Derivative Liabilities – Commodity Contracts	$ 209	$ 1	$ 19	$ 1	$ 12	$ —	$ 2
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

Derivative Assets	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Commodity Contracts							
Not Designated as Hedging Instruments							
Current	$ 12	$ —	$ 1	$ —	$ 1	$ 3	$ 7
Noncurrent	4	—	4	—	4	—	—
Total Derivative Assets – Commodity Contracts	$ 16	$ —	$ 5	$ —	$ 5	$ 3	$ 7
Interest Rate Contracts							
Designated as Hedging Instruments							
Noncurrent	$ 3	$ —	$ —	$ —	$ —	$ —	$ —
Not Designated as Hedging Instruments							
Current	6	—	6	2	2	—	—
Total Derivative Assets – Interest Rate Contracts	$ 9	$ —	$ 6	$ 2	$ 2	$ —	$ —
Total Derivative Assets	$ 25	$ —	$ 11	$ 2	$ 7	$ 3	$ 7

Derivative Liabilities	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Commodity Contracts							
Not Designated as Hedging Instruments							
Current	$ 256	$ 32	$ 222	$ 77	$ 145	$ —	$ —
Noncurrent	100	8	92	16	71	—	—
Total Derivative Liabilities – Commodity Contracts	$ 356	$ 40	$ 314	$ 93	$ 216	$ —	$ —
Interest Rate Contracts							
Designated as Hedging Instruments							
Current	$ 9	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	13	—	—	—	—	—	—
Not Designated as Hedging Instruments							
Current	4	—	3	—	—	1	—
Noncurrent	15	5	5	5	—	6	—
Total Derivative Liabilities – Interest Rate Contracts	$ 41	$ 5	$ 8	$ 5	$ —	$ 7	$ —
Total Derivative Liabilities	$ 397	$ 45	$ 322	$ 98	$ 216	$ 7	$ —

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, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Current							
Gross amounts recognized	**$ 111**	**$ 23**	**$ 64**	**$ 36**	**$ 28**	**$ 4**	**$ 16**
Gross amounts offset	**(11)**	**—**	**(11)**	**—**	**(11)**	**—**	**—**
Net amounts presented in Current Assets: Other	**$ 100**	**$ 23**	**$ 53**	**$ 36**	**$ 17**	**$ 4**	**$ 16**
Noncurrent							
Gross amounts recognized	**$ 51**	**$ 10**	**$ 21**	**$ 10**	**$ 11**	**$ 1**	**$ —**
Gross amounts offset	**(2)**	**(1)**	**(1)**	**(1)**	**—**	**—**	**—**
Net amounts presented in Investments and Other 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**
Current							
Gross amounts recognized	**$ 52**	**$ —**	**$ 12**	**$ —**	**$ 12**	**$ 1**	**$ 2**
Gross amounts offset	**(11)**	**—**	**(11)**	**—**	**(11)**	**—**	**—**
Net amounts presented in Current Liabilities: Other	**$ 41**	**$ —**	**$ 1**	**$ —**	**$ 1**	**$ 1**	**$ 2**
Noncurrent							
Gross amounts recognized	**$ 200**	**$ 16**	**$ 13**	**$ 7**	**$ —**	**$ 5**	**$ —**
Gross amounts offset	**(2)**	**(1)**	**(1)**	**(1)**	**—**	**—**	**—**
Net amounts presented in Deferred Credits and Other Liabilities: Other	**$ 198**	**$ 15**	**$ 12**	**$ 6**	**$ —**	**$ 5**	**$ —**

Derivative Assets	**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							
Gross amounts recognized	$ 18	$ —	$ 7	$ 2	$ 3	$ 3	$ 7
Gross amounts offset	(3)	—	(2)	—	(2)	—	—
Net amounts presented in Current Assets: Other	$ 15	$ —	$ 5	$ 2	$ 1	$ 3	$ 7
Noncurrent							
Gross amounts recognized	$ 7	$ —	$ 4	$ —	$ 4	$ —	$ —
Gross amounts offset	(4)	—	(4)	—	(4)	—	—
Net amounts presented in Investments and Other Assets: Other	$ 3	$ —	$ —	$ —	$ —	$ —	$ —

Derivative Liabilities	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							
Gross amounts recognized	$ 269	$ 32	$ 225	$ 77	$ 145	$ 1	$ —
Gross amounts offset	(22)	—	(21)	(1)	(20)	—	—
Net amounts presented in Current Liabilities: Other	$ 247	$ 32	$ 204	$ 76	$ 125	$ 1	$ —
Noncurrent							
Gross amounts recognized	$ 128	$ 13	$ 97	$ 21	$ 71	$ 6	$ —
Gross amounts offset	(16)	—	(15)	—	(15)	—	—
Net amounts presented in Deferred Credits and Other Liabilities: Other	$ 112	$ 13	$ 82	$ 21	$ 56	$ 6	$ —

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. Amounts for Duke Energy Ohio and Duke Energy Indiana were not material.

	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**

	December 31, 2015				
(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	$ 334	$ 45	$ 290	$ 93	$ 194
Fair value of collateral already posted	30	—	30	—	30
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	304	45	260	93	164

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. At December 31, 2015, receivables of $30 million at Duke Energy Florida related to the right to reclaim cash collateral under master netting arrangements were offset against net derivative positions on the Consolidated Balance Sheets of Duke Energy, Progress Energy and Duke Energy Florida.

15. INVESTMENTS IN DEBT AND EQUITY SECURITIES

TRADING SECURITIES

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 $5 million at December 31, 2016.

AVAILABLE-FOR-SALE SECURITIES

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

Duke Energy's available-for-sale securities are primarily comprised of investments held in (i) the 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.

Other Available-for-Sale Securities

Unrealized gains and losses on all other available-for-sale 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, 2016 and 2015.

DUKE ENERGY

The following table presents the estimated fair value of investments in available-for-sale securities.

	December 31, 2016			December 31, 2015		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses(a)	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses(a)	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 111	$ —	$ —	$ 179
Equity securities	2,092	54	4,106	1,823	58	3,590
Corporate debt securities	10	8	528	7	8	432
Municipal bonds	3	10	331	5	1	185
U.S. government bonds	10	8	984	11	5	1,254
Other debt securities	—	3	124	—	4	177
Total NDTF	$ 2,115	$ 83	$ 6,184	$ 1,846	$ 76	$ 5,817
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 25	$ —	$ —	$ 29
Equity securities	38	—	104	32	1	95
Corporate debt securities	1	1	66	1	3	92
Municipal bonds	2	1	82	3	1	74
U.S. government bonds	—	1	51	—	—	45
Other debt securities	—	2	42	—	2	62
Total Other Investments(b)	$ 41	$ 5	$ 370	$ 36	$ 7	$ 397
Total Investments	$ 2,156	$ 88	$ 6,554	$ 1,882	$ 83	$ 6,214

(a) Substantially all these amounts are considered OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.

(b) These amounts are recorded in Other within Investments and Other Assets on the Consolidated Balance Sheets.

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2016
Due in one year or less	$ 94
Due after one through five years	653
Due after five through 10 years	515
Due after 10 years	946
Total	$ 2,208

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

	Years Ended December 31,		
(in millions)	**2016**	2015	2014
Realized gains	**$ 246**	$ 193	$ 271
Realized losses	**187**	98	105

DUKE ENERGY CAROLINAS

The following table presents the estimated fair value of investments in available-for-sale securities.

	December 31, 2016			**December 31, 2015**		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 18**	$ —	$ —	$ 34
Equity securities	**1,157**	**28**	**2,245**	1,021	27	2,094
Corporate debt securities	**5**	**6**	**354**	3	5	292
Municipal bonds	**1**	**2**	**67**	1	—	33
U.S. government bonds	**2**	**5**	**458**	3	3	438
Other debt securities	**—**	**3**	**116**	—	4	147
Total NDTF	**$ 1,165**	**$ 44**	**$ 3,258**	$ 1,028	$ 39	$ 3,038
Other Investments						
Other debt securities	**$ —**	**$ 1**	**$ 3**	$ —	$ 1	$ 3
Total Other Investments(b)	**$ —**	**$ 1**	**$ 3**	$ —	$ 1	$ 3
Total Investments	**$ 1,165**	**$ 45**	**$ 3,261**	$ 1,028	$ 40	$ 3,041

(a) Substantially all these amounts represent OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.
(b) These amounts are recorded in Other within Investments and Other Assets on the Consolidated Balance Sheets.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2016**
Due in one year or less	**$ 3**
Due after one through five years	**230**
Due after five through 10 years	**260**
Due after 10 years	**505**
Total	**$ 998**

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

	Years Ended December 31,		
(in millions)	**2016**	2015	2014
Realized gains	**$ 157**	$ 158	$ 109
Realized losses	**121**	83	93

PROGRESS ENERGY

The following table presents the estimated fair value of investments in available-for-sale securities.

	December 31, 2016			**December 31, 2015**		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 93**	$ —	$ —	$ 145
Equity securities	**935**	**26**	**1,861**	802	31	1,496
Corporate debt securities	**5**	**2**	**174**	4	3	140
Municipal bonds	**2**	**8**	**264**	4	1	152
U.S. government bonds	**8**	**3**	**526**	8	2	816
Other debt securities	**—**	**—**	**8**	—	—	30
Total NDTF	**$ 950**	**$ 39**	**$ 2,926**	$ 818	$ 37	$ 2,779
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 21**	$ —	$ —	$ 18
Municipal bonds	**2**	**—**	**44**	3	—	45
Total Other Investments(b)	**$ 2**	**$ —**	**$ 65**	$ 3	$ —	$ 63
Total Investments	**$ 952**	**$ 39**	**$ 2,991**	$ 821	$ 37	$ 2,842

(a) Substantially all these amounts represent OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.
(b) These amounts are recorded in Other within Investments and Other Assets on the Consolidated Balance Sheets.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2016**
Due in one year or less	**$ 84**
Due after one through five years	**347**
Due after five through 10 years	**187**
Due after 10 years	**398**
Total	**$ 1,016**

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

	Years Ended December 31,		
(in millions)	**2016**	2015	2014
Realized gains	**$ 84**	$ 33	$ 157
Realized losses	**64**	13	11

DUKE ENERGY PROGRESS

The following table presents the estimated fair value of investments in available-for-sale securities.

	December 31, 2016			**December 31, 2015**		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 45**	$ —	$ —	$ 110
Equity securities	**704**	**21**	**1,505**	596	25	1,178
Corporate debt securities	**4**	**1**	**120**	3	2	96
Municipal bonds	**2**	**8**	**263**	4	1	150
U.S. government bonds	**5**	**2**	**275**	6	2	486
Other debt securities	**—**	**—**	**5**	—	—	18
Total NDTF	**$ 715**	**$ 32**	**$ 2,213**	$ 609	$ 30	$ 2,038
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ 1
Total Other Investments(b)	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ 1
Total Investments	**$ 715**	**$ 32**	**$ 2,214**	$ 609	$ 30	$ 2,039

(a) Substantially all these amounts are considered OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.

(b) These amounts are recorded in Other within Investments and Other Assets on the Consolidated Balance Sheets.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2016**
Due in one year or less	**$ 28**
Due after one through five years	**190**
Due after five through 10 years	**142**
Due after 10 years	**303**
Total	**$ 663**

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

	Years Ended December 31,		
(in millions)	**2016**	2015	2014
Realized gains	**$ 71**	$ 26	$ 19
Realized losses	**55**	11	5

DUKE ENERGY FLORIDA

The following table presents the estimated fair value of investments in available-for-sale securities.

	December 31, 2016			December 31, 2015		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 48**	$ —	$ —	$ 35
Equity securities	**231**	**5**	**356**	206	6	318
Corporate debt securities	**1**	**1**	**54**	1	1	44
Municipal bonds	**—**	**—**	**1**	—	—	2
U.S. government bonds	**3**	**1**	**251**	2	—	330
Other debt securities	**—**	**—**	**3**	—	—	12
Total NDTF(b)	**$ 235**	**$ 7**	**$ 713**	$ 209	$ 7	$ 741
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 4**	$ —	$ —	$ 6
Municipal bonds	**2**	**—**	**44**	3	—	45
Total Other Investments(c)	**$ 2**	**$ —**	**$ 48**	$ 3	$ —	$ 51
Total Investments	**$ 237**	**$ 7**	**$ 761**	$ 212	$ 7	$ 792

(a) Substantially all these amounts are considered OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.
(b) The decrease in estimated fair value of the NDTF as of December 31, 2016, is primarily due to reimbursements from the NDTF for costs related to ongoing decommissioning activity of Crystal River Unit 3.
(c) These amounts are recorded in Other within Investments and Other Assets on the Consolidated Balance Sheets.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2016**
Due in one year or less	**$ 56**
Due after one through five years	**157**
Due after five through 10 years	**45**
Due after 10 years	**95**
Total	**$ 353**

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

	Years Ended December 31,		
(in millions)	**2016**	2015	2014
Realized gains	**$ 13**	$ 7	$ 138
Realized losses	**9**	2	5

DUKE ENERGY INDIANA

The following table presents the estimated fair value of investments in available-for-sale securities.

	December 31, 2016			**December 31, 2015**		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses(a)**	**Estimated Fair Value**
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ —**	$ —	$ —	$ 2
Equity securities	**33**	**—**	**79**	27	—	71
Corporate debt securities	**—**	**—**	**2**	—	—	2
Municipal bonds	**—**	**1**	**28**	—	1	26
U.S. government bonds	**—**	**—**	**1**	—	—	—
Total Other Investments(b)	**$ 33**	**$ 1**	**$ 110**	$ 27	$ 1	$ 101
Total Investments	**$ 33**	**$ 1**	**$ 110**	$ 27	$ 1	$ 101

(a) Substantially all these amounts are considered OTTIs on investments within Investment Trusts that have been recognized immediately as a regulatory asset.

(b) These amounts are recorded in Other within Investments and Other Assets on the Consolidated Balance Sheets.

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2016**
Due in one year or less	**$ 3**
Due after one through five years	**13**
Due after five through 10 years	**9**
Due after 10 years	**6**
Total	**$ 31**

Realized gains and losses, which were determined on a specific identification basis, from sales of available-for-sale securities were insignificant for the years ended December 31, 2016, 2015 and 2014.

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, (iii) and 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 1 and 2 during the years ended December 31, 2016, 2015 and 2014. Transfers out of Level 3 during the year ended December 31, 2014, were the result of forward commodity prices becoming observable due to the passage of time.

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 are primarily valued using internally developed discounted cash flow models which 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 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 which 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 exclude cash collateral which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type.

	December 31, 2016				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
Nuclear decommissioning trust fund equity securities	**$ 4,106**	**$ 4,029**	**$ —**	**$ —**	**$ 77**
Nuclear decommissioning trust fund debt securities	**2,078**	**632**	**1,446**	**—**	**—**
Other trading and available-for-sale equity securities	**104**	**104**	**—**	**—**	**—**
Other trading and available-for-sale 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 (liabilities)	**$ 6,464**	**$ 4,843**	**$ 1,705**	**$ (161)**	**$ 77**

	December 31, 2015				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
Nuclear decommissioning trust fund equity securities	$ 3,590	$ 3,418	$ —	$ —	$ 172
Nuclear decommissioning trust fund debt securities	2,227	672	1,555	—	—
Other available-for-sale equity securities	95	95	—	—	—
Other available-for-sale debt securities	302	75	222	5	—
Derivative assets	25	—	15	10	—
Total assets	6,239	4,260	1,792	15	172
Derivative liabilities	(397)	—	(397)	—	—
Net assets	$ 5,842	$ 4,260	$ 1,395	$ 15	$ 172

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 Operating Revenues.

	December 31, 2016		
(in millions)	**Investments**	**Derivatives (net)**	**Total**
Balance at beginning of period	$ 5	$ 10	$ 15
Derivative liability resulting from the acquisition of Piedmont	—	(187)	(187)
Purchases, sales, issuances and settlements:			
Purchases	—	33	33
Settlements	—	(28)	(28)
Total gains included on the Consolidated Balance Sheet as regulatory assets or liabilities	—	6	6
Balance at end of period	$ 5	$ (166)	$ (161)

	December 31, 2015		
(in millions)	**Investments**	**Derivatives (net)**	**Total**
Balance at beginning of period	$ 5	$ (1)	$ 4
Total pretax realized or unrealized gains (losses) included in earnings	—	21	21
Purchases, sales, issuances and settlements:			
Purchases	—	24	24
Sales	—	(1)	(1)
Settlements	—	(37)	(37)
Total gains included on the Consolidated Balance Sheet as regulatory assets or liabilities	—	4	4
Balance at end of period	$ 5	$ 10	$ 15

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. Derivative amounts in the table below exclude cash collateral, which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type.

	December 31, 2016				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
Nuclear decommissioning trust fund equity securities	$ 2,245	$ 2,168	$ —	$ —	$ 77
Nuclear decommissioning trust fund debt securities	1,013	178	835	—	—
Other available-for-sale 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

	December 31, 2015				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
Nuclear decommissioning trust fund equity securities	$ 2,094	$ 1,922	$ —	$ —	$ 172
Nuclear decommissioning trust fund debt securities	944	246	698	—	—
Other available-for-sale debt securities	3	—	—	3	—
Total assets	3,041	2,168	698	3	172
Derivative liabilities	(45)	—	(45)	—	—
Net assets	$ 2,996	$ 2,168	$ 653	$ 3	$ 172

There was no change to the Level 3 balance during the years ended December 31, 2016 and 2015.

PROGRESS 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 exclude cash collateral, which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type.

	December 31, 2016		
(in millions)	Total Fair Value	Level 1	Level 2
Nuclear decommissioning trust fund equity securities	**$ 1,861**	**$ 1,861**	**$ —**
Nuclear decommissioning trust fund debt securities	**1,065**	**454**	**611**
Other available-for-sale debt securities	**65**	**21**	**44**
Derivative assets	**85**	**—**	**85**
Total assets	**3,076**	**2,336**	**740**
Derivative liabilities	**(25)**	**—**	**(25)**
Net assets	**$ 3,051**	**$ 2,336**	**$ 715**

	December 31, 2015		
(in millions)	Total Fair Value	Level 1	Level 2
Nuclear decommissioning trust fund equity securities	$ 1,496	$ 1,496	$ —
Nuclear decommissioning trust fund debt securities	1,283	426	857
Other available-for-sale debt securities	63	18	45
Derivative assets	11	—	11
Total assets	2,853	1,940	913
Derivative liabilities	(322)	—	(322)
Net assets	$ 2,531	$ 1,940	$ 591

DUKE ENERGY PROGRESS

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 exclude cash collateral which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type.

	December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**
Nuclear decommissioning trust fund equity securities	**$ 1,505**	**$ 1,505**	**$ —**
Nuclear decommissioning trust fund debt securities and other	**708**	**207**	**501**
Other available-for-sale debt securities and other	**1**	**1**	**—**
Derivative assets	**46**	**—**	**46**
Total assets	**2,260**	**1,713**	**547**
Derivative liabilities	**(7)**	**—**	**(7)**
Net assets	**$ 2,253**	**$ 1,713**	**$ 540**

	December 31, 2015		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**
Nuclear decommissioning trust fund equity securities	$ 1,178	$ 1,178	$ —
Nuclear decommissioning trust fund debt securities and other	860	141	719
Other available-for-sale debt securities and other	1	1	—
Derivative assets	2	—	2
Total assets	2,041	1,320	721
Derivative liabilities	(98)	—	(98)
Net assets	$ 1,943	$ 1,320	$ 623

DUKE ENERGY FLORIDA

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 exclude cash collateral which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type.

	December 31, 2016		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**
Nuclear decommissioning trust fund equity securities	**$ 356**	**$ 356**	**$ —**
Nuclear decommissioning trust fund debt securities and other	**357**	**247**	**110**
Other available-for-sale debt securities and other	**48**	**4**	**44**
Derivative assets	**39**	**—**	**39**
Total assets	**800**	**607**	**193**
Derivative liabilities	**(12)**	**—**	**(12)**
Net assets	**$ 788**	**$ 607**	**$ 181**

	December 31, 2015		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**
Nuclear decommissioning trust fund equity securities	$ 318	$ 318	$ —
Nuclear decommissioning trust fund debt securities and other	423	285	138
Other available-for-sale debt securities and other	51	6	45
Derivative assets	7	—	7
Total assets	799	609	190
Derivative liabilities	(216)	—	(216)
Net assets (liabilities)	$ 583	$ 609	$ (26)

DUKE ENERGY OHIO

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 exclude cash collateral, which are disclosed in Note 14.

	December 31, 2016			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Derivative assets	**$ 5**	**$ —**	**$ —**	**$ 5**
Derivative liabilities	**(6)**	**—**	**(6)**	**—**
Net (liabilities) assets	**$ (1)**	**$ —**	**$ (6)**	**$ 5**

	December 31, 2015			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Derivative assets	$ 3	$ —	$ —	$ 3
Derivative liabilities	(7)	—	(7)	—
Net (liabilities) assets	$ (4)	$ —	$ (7)	$ 3

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)	**2016**	**2015**
Balance at beginning of period	**$ 3**	$ (18)
Total pretax realized or unrealized gains (losses) included in earnings	**—**	21
Purchases, sales, issuances and settlements:		
Purchases	**5**	5
Settlements	**(5)**	(5)
Total gains included on the Consolidated Balance Sheet as regulatory assets or liabilities	**2**	—
Balance at end of period	**$ 5**	$ 3

DUKE ENERGY INDIANA

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 exclude cash collateral, which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type.

	December 31, 2016			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Other available-for-sale equity securities	**$ 79**	**$ 79**	**$ —**	**$ —**
Other available-for-sale debt securities and other	**31**	**—**	**31**	**—**
Derivative assets	**16**	**—**	**—**	**16**
Total assets	**126**	**79**	**31**	**16**
Derivative liabilities	**(2)**	**(2)**	**—**	**—**
Net assets	**$ 124**	**$ 77**	**$ 31**	**$ 16**

	December 31, 2015			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Other available-for-sale equity securities	$ 71	$ 71	$ —	$ —
Other available-for-sale debt securities and other	30	2	28	—
Derivative assets	7	—	—	7
Net assets	$ 108	$ 73	$ 28	$ 7

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)	**2016**	**2015**
Balance at beginning of period	**$ 7**	$ 14
Purchases, sales, issuances and settlements:		
Purchases	**29**	19
Settlements	**(24)**	(30)
Total gains included on the Consolidated Balance Sheet as regulatory assets or liabilities	**4**	4
Balance at end of period	**$ 16**	$ 7

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

The following table includes quantitative information about the Duke Energy Registrants' derivatives classified as Level 3.

	December 31, 2016					
Investment Type	**Fair Value (in millions)**		**Valuation Technique**	**Unobservable Input**	**Range**	
Duke Energy						
Natural gas contracts	**$**	**(187)**	Discounted cash flow	Forward natural gas curves - price per million British thermal unit (MMBtu)	**$ 2.31** -	**$ 4.18**
Financial Transmission Rights (FTRs)		**21**	RTO auction pricing	FTR price – per megawatt-hour (MWh)	**(0.83)** -	**9.32**
Total Level 3 derivatives	**$**	**(166)**				
Duke Energy Ohio	**$**	**5**	RTO auction pricing	FTR price – per MWh	**$ 0.77** -	**$ 3.52**
Duke Energy Indiana		**16**	RTO auction pricing	FTR price – per MWh	**(0.83)** -	**9.32**

	December 31, 2015					
Investment Type	**Fair Value (in millions)**		**Valuation Technique**	**Unobservable Input**	**Range**	
Duke Energy	$	10	RTO auction pricing	FTR price – per MWh	$ (0.74) -	$ 7.29
Duke Energy Ohio		3	RTO auction pricing	FTR price – per MWh	0.67 -	2.53
Duke Energy Indiana		7	RTO auction pricing	FTR price – per MWh	(0.74) -	7.29

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, 2016		December 31, 2015	
(in millions)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Duke Energy	**$ 47,895**	**$ 49,161**	$ 38,868	$ 41,767
Duke Energy Carolinas	**9,603**	**10,494**	8,367	9,156
Progress Energy	**17,541**	**19,107**	14,464	15,856
Duke Energy Progress	**7,011**	**7,357**	6,518	6,757
Duke Energy Florida	**6,125**	**6,728**	4,266	4,908
Duke Energy Ohio	**1,884**	**2,020**	1,598	1,724
Duke Energy Indiana	**3,786**	**4,260**	3,768	4,219

At both December 31, 2016 and December 31, 2015, fair value of cash and cash equivalents, accounts and notes receivable, accounts payable, notes payable and commercial paper and non-recourse 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, 2016, 2015 and 2014, 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 2018	December 2018	February 2019	April 2019
Credit facility amount (in millions)	$ 325	$ 425	$ 300	$ 225
Amounts borrowed at December 31, 2016	325	425	300	225
Amounts borrowed at December 31, 2015	325	425	254	225

Nuclear Asset-Recovery Bonds – DEFPF

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, 2016
Receivables of VIEs	**$ 6**
Regulatory Assets: Current	**50**
Current Assets: Other	**53**
Regulatory Assets and Deferred Debits: Regulatory assets	**1,142**
Current Liabilities: Other	**17**
Current maturities of long-term debt	**62**
Long-Term Debt	**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, 2016	December 31, 2015
Current Assets: Other	$ 223	$ 138
Property, plant and equipment, cost	3,419	2,015
Accumulated depreciation and amortization	(453)	(321)
Current maturities of long-term debt	198	108
Long-Term Debt	1,097	968
Deferred Credits and Other Liabilities: Deferred income taxes	275	289
Deferred Credits and Other Liabilities: Other	252	33

NON-CONSOLIDATED VIEs

The following tables summarize the impact of non-consolidated VIEs on the Consolidated Balance Sheets.

	December 31, 2016					
	Duke Energy					
(in millions)	Pipeline Investments	Commercial Renewables	Other	Total	Duke Energy Ohio	Duke Energy Indiana
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 82	$ 101
Investments in equity method unconsolidated affiliates	487	174	90	751	—	—
Investments and other assets	12	—	—	12	—	—
Total assets	$ 499	$ 174	$ 90	$ 763	$ 82	$ 101
Other current liabilities	—	—	3	3	—	—
Deferred credits and other liabilities	—	—	13	13	—	—
Total liabilities	$ —	$ —	$ 16	$ 16	$ —	$ —
Net assets (liabilities)	$ 499	$ 174	$ 74	$ 747	$ 82	$ 101

	December 31, 2015					
	Duke Energy					
(in millions)	Pipeline Investments	Commercial Renewables	Other	Total	Duke Energy Ohio	Duke Energy Indiana
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 47	$ 60
Investments in equity method unconsolidated affiliates	113	235	39	387		—
Total assets	$ 113	$ 235	$ 39	$ 387	$ 47	$ 60
Other current liabilities	—	—	3	3	—	—
Deferred credits and other liabilities	—	—	14	14	—	—
Total liabilities	$ —	$ —	$ 17	$ 17	$ —	$ —
Net assets	$ 113	$ 235	$ 22	$ 370	$ 47	$ 60

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 Deferred credits and other 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(a)	December 31, 2016	December 31, 2015
ACP	47%	**$ 265**	$ 52
Sabal Trail	7.5%	**140**	61
Constitution	24%	**82**	—
Total		**$ 487**	$ 113

(a) The percentages presented reflect Duke Energy's ownership interest as of December 31, 2016. The investment amount presented for ACP as of December 31, 2015, reflects 40 percent ownership interest prior to acquiring an additional 7 percent as a result of the Piedmont acquisition. See Notes 2 and 4 for additional information related to the Piedmont acquisition and increased ownership of ACP.

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.

During the year ended December 31, 2016, Duke Energy recorded a $71 million pretax OTTI of certain wind project investments within Equity in earnings (losses) of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations. See Note 12 for additional information related to the OTTI.

Other

Duke Energy holds a 50 percent equity interest in DATC. DATC is considered a VIE due to having insufficient equity to finance their own activities without subordinated financial support. The activities that most significantly impact DATC's economic performance are decisions related to investing in existing and 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 Transmission Company, LLC, therefore Duke Energy does not consolidate DATC.

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	
	2016	**2015**	**2016**	**2015**
Anticipated credit loss ratio	**0.5%**	0.6%	**0.3%**	0.3%
Discount rate	**1.5%**	1.2%	**1.5%**	1.2%
Receivable turnover rate	**13.3%**	12.9%	**10.6%**	10.6%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio		Duke Energy Indiana	
(in millions)	**2016**	**2015**	**2016**	**2015**
Receivables sold	**$ 267**	$ 233	**$ 306**	$ 260
Less: Retained interests	**82**	47	**101**	60
Net receivables sold	**$ 185**	$ 186	**$ 205**	$ 200

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)	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Sales						
Receivables sold	**$ 1,926**	$ 1,963	$ 2,246	**$ 2,635**	$ 2,627	$ 2,913
Loss recognized on sale	**9**	9	11	**11**	11	11
Cash Flows						
Cash proceeds from receivables sold	**1,882**	1,995	2,261	**2,583**	2,670	2,932
Collection fees received	**1**	1	1	**1**	1	1
Return received on retained interests	**2**	3	4	**5**	5	6

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, adjusted for distributed and undistributed earnings allocated to participating securities, by the weighted average number of common stock 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 stock outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, 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)	**2016**	**2015**	**2014**
Income from continuing operations attributable to Duke Energy common stockholders excluding impact of participating securities	**$ 2,567**	$ 2,640	$ 2,529
Weighted average shares outstanding – basic	**691**	694	707
Weighted average shares outstanding – diluted	**691**	694	707
Earnings per share from continuing operations attributable to Duke Energy common stockholders			
Basic	**$ 3.71**	3.80	3.58
Diluted	**$ 3.71**	3.80	3.58
Potentially dilutive items excluded from the calculation[a]	**2**	2	2
Dividends declared per common share	**$ 3.36**	3.24	3.15

(a) Performance stock awards were not included in the dilutive securities calculation because the performance measures related to the awards had not been met.

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.

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 strategic planning processes launched in 2015, Duke Energy continued to implement targeted cost savings initiatives during 2016 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.

Also 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 are a part of the synergies expected to be realized with the acquisition. Refer to Note 2 for additional information on the Piedmont acquisition.

As part of the cost savings initiatives and the Piedmont integration, voluntary and involuntary severance benefit costs were accrued for a total of approximately 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
Year Ended December 31, 2016	**$ 118**	**$ 39**	**$ 40**	**$ 23**	**$ 17**	**$ 3**	**$ 7**
Year Ended December 31, 2015	142	93	36	28	8	2	6

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
Balance at December 31, 2015	$ 136	$ 78	$ 23	$ 19	$ 4
Provision/Adjustments	**110**	**18**	**20**	**11**	**9**
Cash Reductions	**(167)**	**(83)**	**(29)**	**(24)**	**(5)**
Balance at December 31, 2016	**$ 79**	**$ 13**	**$ 14**	**$ 6**	**$ 8**

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)	2016	2015	2014
Duke Energy	**$ 35**	$ 38	$ 38
Duke Energy Carolinas	**12**	14	12
Progress Energy	**12**	14	14
Duke Energy Progress	**7**	9	9
Duke Energy Florida	**5**	5	5
Duke Energy Ohio	**2**	2	5
Duke Energy Indiana	**3**	4	3

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)	2016	2015	2014
Restricted stock unit awards	**$ 36**	$ 38	$ 39
Performance awards	**19**	23	22
Pretax stock-based compensation cost	**$ 55**	$ 61	$ 61
Tax benefit associated with stock-based compensation expense	**$ 20**	$ 23	$ 23
Stock-based compensation costs capitalized	**2**	3	4

RESTRICTED STOCK UNIT AWARDS

Restricted stock unit 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,		
	2016	2015	2014
Shares awarded (in thousands)	684	524	557
Fair value (in millions)	$ 52	$ 41	$ 40

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, 2015	953	$ 75
Piedmont transfers in	113	79
Granted	684	75
Vested	(525)	73
Forfeited	(86)	76
Outstanding at December 31, 2016	1,139	76
Restricted stock unit awards expected to vest	1,056	76

The total grant date fair value of shares vested during the years ended December 31, 2016, 2015 and 2014 was $38 million, $41 million and $52 million, respectively. At December 31, 2016, Duke Energy had $27 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of one year, ten months.

PERFORMANCE AWARDS

Stock-based performance awards generally vest after three years if performance targets are met.

Performance awards granted in 2016, 2015 and 2014 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 2016, the model used a risk-free interest rate of 0.9 percent, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 16.1 percent based on Duke Energy's historical volatility over three years using daily stock prices. The performance awards granted in 2016 also contain a performance condition based on Duke Energy's cumulative adjusted EPS.

The following table includes information related to stock-based performance awards.

	Years Ended December 31,		
	2016	2015	2014
Shares awarded (in thousands)	675	642	542
Fair value (in millions)	$ 25	$ 26	$ 19

The following table summarizes information about stock-based performance awards outstanding and assumes payout at the maximum level.

	Shares (in thousands)	Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2015	1,697	$ 40
Granted	**675**	**38**
Vested	**(544)**	**46**
Forfeited	**(104)**	**38**
Outstanding at December 31, 2016	**1,724**	**38**
Stock-based performance awards expected to vest	**1,199**	**38**

The total grant date fair value of shares vested during the years ended December 31, 2016, 2015 and 2014 was $25 million, $26 million and $27 million, respectively. At December 31, 2016, Duke Energy had $24 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of one year, ten months.

STOCK OPTIONS

Stock options are granted with 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. The following table summarizes information about stock options outstanding.

	Stock Options (in thousands)	Weighted Average Exercise Price (per share)
Outstanding at December 31, 2015	103	$ 69
Exercised	**(103)**	**69**
Outstanding at December 31, 2016	**—**	**—**

The following table summarizes additional information related to stock options exercised and granted.

	Years Ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Intrinsic value of options exercised	**$ 1**	$ 5	$ 6
Tax benefit related to options exercised	**—**	2	2
Cash received from options exercised	**7**	17	25

21. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT RETIREMENT PLANS

Duke Energy or its affiliates maintain, and the Subsidiary Registrants participate in, qualified, non-contributory defined benefit retirement plans. The plans cover most U.S. 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 based on age, or age and years of service and interest credits. Certain employees are covered under plans that use a final average earnings formula. Under these 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 which cover certain executives. As of January 1, 2014, the qualified and non-qualified non-contributory defined benefit plans are closed to new and rehired non-union and certain unionized employees. Piedmont employees hired or rehired after December 31, 2007, cannot participate in the qualified non-contributory defined benefit plans, but are participants in the Money Purchase Pension (MPP) plan, discussed below.

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 U.S. 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
Anticipated Contributions:								
	2017	$ 160	$ 45	$ 45	$ 25	$ 20	$ 4	$ 9
Contributions Made:								
	2016	**$ 155**	**$ 43**	**$ 43**	**$ 24**	**$ 20**	**$ 5**	**$ 9**
	2015	302	91	83	42	40	8	19
	2014	—	—	—	—	—	—	—

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	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

	Year Ended December 31, 2014						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 135	$ 41	$ 40	$ 21	$ 20	$ 4	$ 9
Interest cost on projected benefit obligation	344	85	112	54	57	20	29
Expected return on plan assets	(511)	(132)	(173)	(85)	(85)	(27)	(41)
Amortization of actuarial loss	150	36	68	32	32	4	13
Amortization of prior service credit	(15)	(8)	(3)	(2)	(1)	—	—
Other	8	2	3	1	1	—	1
Net periodic pension costs(a)(b)	$ 111	$ 24	$ 47	$ 21	$ 24	$ 1	$ 11

(a) Duke Energy amounts exclude $8 million, $9 million and $10 million for the years ended December 2016, 2015 and 2014, 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 $4 million, $4 million and $5 million for the years ended December 2016, 2015 and 2014, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	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 loss (income)							
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)**	**$ —**	**$ —**	**$ —**	**$ —**

	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**
Regulatory assets, net increase (decrease)	$ 173	$ 65	$ 18	$ 14	$ 4	$ 14	$ 11
Accumulated other comprehensive (income) loss							
Deferred income tax expense	$ 6	$ —	$ 5	$ —	$ —	$ —	$ —
Actuarial losses arising during the year	4	—	—	—	—	—	—
Prior year service credit arising during the year	1	—	—	—	—	—	—
Amortization of prior year actuarial losses	(11)	—	(4)	—	—	—	—
Transfer with the Midwest Generation Disposal Group	3	—	—	—	—	—	—
Reclassification of actuarial losses to regulatory assets	(6)	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (3)	$ —	$ 1	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

	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)

	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**
Change in Projected Benefit Obligation							
Obligation at prior measurement date	$ 8,107	$ 2,053	$ 2,557	$ 1,187	$ 1,335	$ 469	$ 673
Obligation transferred with Midwest Generation Disposal Group	(83)	—	—	—	—	—	—
Service cost	159	50	44	23	20	4	10
Interest cost	324	83	104	48	54	18	27
Actuarial gain	(241)	(53)	(111)	(46)	(62)	(9)	(15)
Transfers	—	8	4	7	(3)	8	—
Plan amendments	(6)	—	—	—	—	—	(4)
Benefits paid	(533)	(146)	(147)	(76)	(68)	(37)	(42)
Obligation at measurement date	$ 7,727	$ 1,995	$ 2,451	$ 1,143	$ 1,276	$ 453	$ 649
Accumulated Benefit Obligation at measurement date	$ 7,606	$ 1,993	$ 2,414	$ 1,143	$ 1,240	$ 442	$ 628
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	$ 8,498	$ 2,300	$ 2,722	$ 1,321	$ 1,363	$ 456	$ 681
Obligation transferred with Midwest Generation Disposal Group	(81)	—	—	—	—	—	—
Employer contributions	302	91	83	42	40	8	19
Actual return on plan assets	(50)	(10)	(22)	(10)	(11)	(2)	(3)
Benefits paid	(533)	(146)	(147)	(76)	(68)	(37)	(42)
Transfers	—	8	4	7	(3)	8	—
Plan assets at measurement date	$ 8,136	$ 2,243	$ 2,640	$ 1,284	$ 1,321	$ 433	$ 655
Funded status of plan	$ 409	$ 248	$ 189	$ 141	$ 45	$ (20)	$ 6

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Prefunded pension[(a)]	$ 518	$ 273	$ 225	$ 132	$ 91	$ 6	$ —
Noncurrent pension liability[(b)]	$ 118	$ —	$ 62	$ —	$ 62	$ 25	$ 1
Net asset recognized	$ 400	$ 273	$ 163	$ 132	$ 29	$ (19)	$ (1)
Regulatory assets	$ 2,098	$ 476	$ 805	$ 378	$ 426	$ 81	$ 171
Accumulated other comprehensive (income) loss							
Deferred income tax asset	$ (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
Unrecognized prior service credit	(24)	(8)	(3)	(2)	(1)	—	(2)

	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Prefunded pension[(a)]	$ 474	$ 252	$ 232	$ 145	$ 84	$ 1	$ 6
Noncurrent pension liability[(b)]	$ 65	$ 4	$ 43	$ 4	$ 39	$ 21	$ —
Net asset recognized	$ 409	$ 248	$ 189	$ 141	$ 45	$ (20)	$ 6
Regulatory assets	$ 1,884	$ 472	$ 771	$ 360	$ 410	$ 79	$ 162
Accumulated other comprehensive (income) loss							
Deferred income tax asset	$ (45)	$ —	$ (6)	$ —	$ —	$ —	$ —
Prior service credit	(4)	—	—	—	—	—	—
Net actuarial loss	130	—	17	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss[(c)]	$ 81	$ —	$ 11	$ —	$ —	$ —	$ —

(a) Included in Other within Investments and Other Assets on the Consolidated Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Consolidated Balance Sheets.

(c) Excludes accumulated other comprehensive income of $13 million as of December 31, 2015, net of tax, associated with a Brazilian retirement plan.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	December 31, 2016			
(in millions)	**Duke Energy**	**Progress Energy**	**Duke Energy Florida**	**Duke 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**

	December 31, 2015			
(in millions)	**Duke Energy**	**Progress Energy**	**Duke Energy Florida**	**Duke Energy Ohio**
Projected benefit obligation	$ 1,216	$ 611	$ 611	$ 307
Accumulated benefit obligation	1,158	575	575	298
Fair value of plan assets	1,151	574	574	289

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 nine years for Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana.

The following tables present the assumptions or range of assumptions used for pension benefit accounting.

	December 31,		
	2016	**2015**	**2014**
Benefit Obligations			
Discount rate	**4.10%**	4.40%	4.10%
Salary increase	**4.00% - 4.50%**	4.00% - 4.40%	4.00% - 4.40%
Net Periodic Benefit Cost			
Discount rate	**4.40%**	4.10%	4.70%
Salary increase	**4.00% - 4.40%**	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%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Years ending December 31,							
2017	$ 585	$ 162	$ 159	$ 84	$ 74	$ 35	$ 49
2018	595	171	159	83	75	33	49
2019	613	177	164	86	76	33	48
2020	632	186	171	90	79	34	47
2021	637	181	175	92	81	35	48
2022 – 2026	3,099	867	890	455	425	161	219

NON-QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	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

	Year Ended December 31, 2014						
(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	$ —	$ —	$ —
Interest cost on projected benefit obligation	14	1	5	1	2	—	—
Amortization of actuarial loss	3	—	2	—	—	—	—
Amortization of prior service credit	(1)	—	(1)	—	—	—	—
Net periodic pension costs	$ 19	$ 1	$ 7	$ 2	$ 2	$ —	$ —

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	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)
Regulatory liabilities, net increase (decrease)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Accumulated other comprehensive (income) loss							
Deferred income tax benefit	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit arising during the year	(1)	—	—	—	—	—	—
Actuarial loss arising during the year	1	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

	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
Regulatory assets, net (decrease) increase	$ (13)	$ 2	$ (16)	$ (1)	$ (15)	$ —	$ (1)
Accumulated other comprehensive (income) loss							
Deferred income tax benefit	$ (7)	$ —	$ (5)	$ —	$ —	$ —	$ —
Amortization of prior service credit	1	—	—	—	—	—	—
Actuarial gains arising during the year	17	—	13	—	—	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$ 11	$ —	$ 8	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

	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	**$ 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	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	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**
Change in Projected Benefit Obligation							
Obligation at prior measurement date	$ 337	$ 16	$ 116	$ 35	$ 61	$ 4	$ 5
Service cost	3	—	1	—	—	—	—
Interest cost	13	1	4	1	2	—	—
Actuarial losses (gains)	10	1	(1)	—	(14)	—	—
Transfers	4	—	—	—	—	—	—
Benefits paid	(26)	(2)	(8)	(3)	(3)	—	—
Obligation at measurement date	$ 341	$ 16	$ 112	$ 33	$ 46	$ 4	$ 5
Accumulated Benefit Obligation at measurement date	$ 336	$ 16	$ 112	$ 33	$ 46	$ 4	$ 5
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	—	—	—	—	—	—	—
Benefits paid	(26)	(2)	(8)	(3)	(3)	—	—
Employer contributions	26	2	8	3	3	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Amounts Recognized in the Consolidated Balance Sheets

	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 pension liability[a]	**$ 28**	**$ 2**	**$ 8**	**$ 2**	**$ 3**	**$ —**	**$ —**
Noncurrent pension liability[b]	**304**	**12**	**106**	**31**	**43**	**4**	**3**
Total accrued pension liability	**$ 332**	**$ 14**	**$ 114**	**$ 33**	**$ 46**	**$ 4**	**$ 3**
Regulatory assets	**$ 73**	**$ 5**	**$ 18**	**$ 7**	**$ 11**	**$ 1**	**$ —**
Accumulated other comprehensive (income) loss							
Deferred income tax asset	**$ (3)**	**$ —**	**$ (3)**	**$ —**	**$ —**	**$ —**	**$ —**
Prior service credit	**(1)**	**—**	**—**	**—**	**—**	**—**	**—**
Net actuarial loss	**10**	**—**	**9**	**—**	**—**	**—**	**—**
Net amounts recognized in accumulated other comprehensive income	**$ 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)**	**—**	**—**	**—**	**—**	**—**	**—**

	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 pension liability[a]	$ 27	$ 2	$ 8	$ 3	$ 3	$ —	$ —
Noncurrent pension liability[b]	314	14	104	30	43	4	5
Total accrued pension liability	$ 341	$ 16	$ 112	$ 33	$ 46	$ 4	$ 5
Regulatory assets	$ 76	$ 7	$ 16	$ 6	$ 10	$ 1	$ 1
Accumulated other comprehensive (income) loss							
Deferred income tax asset	$ (3)	$ —	$ (3)	$ —	$ —	$ —	$ —
Net actuarial loss	9	—	9	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 6	$ —	$ 6	$ —	$ —	$ —	$ —

(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, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Projected benefit obligation	$ **332**	$ **14**	$ **114**	$ **33**	$ **46**	$ **4**	$ **3**
Accumulated benefit obligation	**332**	**14**	**114**	**33**	**46**	**4**	**3**

	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Projected benefit obligation	$ 341	$ 16	$ 112	$ 33	$ 46	$ 4	$ 5
Accumulated benefit obligation	336	16	112	33	46	4	5

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 10 years for Duke Energy, seven years for Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana, 14 years for Progress Energy, 12 years for Duke Energy Progress and 15 years for Duke Energy Florida.

The following tables present the assumptions used for pension benefit accounting.

	December 31,		
	2016	2015	2014
Benefit Obligations			
Discount rate	**4.10%**	4.40%	4.10%
Salary increase	**4.40%**	4.40%	4.40%
Net Periodic Benefit Cost			
Discount rate	**4.40%**	4.10%	4.70%
Salary increase	**4.40%**	4.40%	4.40%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Years ending December 31,							
2017	$ 29	$ 2	$ 8	$ 3	$ 3	$ —	$ —
2018	25	2	8	3	3	—	—
2019	25	2	8	2	3	—	—
2020	24	2	8	2	3	—	—
2021	24	1	8	2	3	—	—
2021 - 2025	111	5	36	11	15	1	1

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 co-payments.

Duke Energy did not make any pre-funding contributions to its other post-retirement benefit plans during the years ended December 31, 2016, 2015 or 2014.

Components of Net Periodic Other Post-Retirement Benefit Costs

	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

	Year Ended December 31, 2014						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 10	$ 2	$ 4	$ 1	$ 3	$ —	$ 1
Interest cost on accumulated post-retirement benefit obligation	49	12	22	11	12	2	5
Expected return on plan assets	(13)	(9)	—	—	—	—	(1)
Amortization of actuarial loss (gain)	39	3	42	31	10	(2)	—
Amortization of prior service credit	(125)	(11)	(95)	(73)	(21)	—	—
Net periodic post-retirement benefit costs(a)(b)	$ (40)	$ (3)	$ (27)	$ (30)	$ 4	$ —	$ 5

(a) Duke Energy amounts exclude $8 million, $10 million and $9 million for the years ended December 2016, 2015 and 2014, 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, $3 million and $2 million for the years ended December 2016, 2015 and 2014, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	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**	**$ —**	**$ —**	**$ —**	**$ —**

	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**
Regulatory assets, net increase (decrease)	$ 1	$ —	$ 1	$ —	$ 1	$ —	$ (7)
Regulatory liabilities, net increase (decrease)	$ (92)	$ (8)	$ (71)	$ (36)	$ (35)	$ 2	$ (8)
Accumulated other comprehensive (income) loss							
Deferred income tax benefit	$ 2	$ —	$ (1)	$ —	$ —	$ —	$ —
Actuarial losses (gains) arising during the year	(5)	—	2	—	—	—	—
Transfer with the Midwest Generation Disposal Group	(3)	—	—	—	—	—	—
Amortization of prior year prior service credit	3	—	(1)	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (3)	$ —	$ —	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	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

	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
Change in Projected Benefit Obligation							
Accumulated post-retirement benefit obligation at prior measurement date	$ 916	$ 220	$ 379	$ 207	$ 170	$ 39	$ 96
Service cost	6	1	1	1	1	—	1
Interest cost	36	9	15	8	7	2	4
Plan participants' contributions	20	4	7	4	3	1	2
Actuarial (gains) losses	(39)	(18)	(1)	(13)	11	(3)	1
Transfers	—	2	—	—	—	—	—
Plan amendments	(9)	—	—	—	—	(1)	(4)
Benefits paid	(100)	(18)	(47)	(19)	(28)	(3)	(13)
Obligations transferred with the Midwest Generation Disposal Group	(3)	—	—	—	—	—	—
Accrued retiree drug subsidy	1	—	—	—	—	—	—
Accumulated post-retirement benefit obligation at measurement date	$ 828	$ 200	$ 354	$ 188	$ 164	$ 35	$ 87
Change in Fair Value of Plan Assets							
Plan assets at prior measurement date	$ 227	$ 145	$ —	$ (1)	$ —	$ 8	$ 23
Actual return on plan assets	(1)	(1)	1	1	1	—	(1)
Benefits paid	(100)	(18)	(47)	(19)	(28)	(3)	(13)
Employer contributions	62	4	39	15	25	2	8
Plan participants' contributions	20	4	7	4	3	1	2
Plan assets at measurement date	$ 208	$ 134	$ —	$ —	$ 1	$ 8	$ 19

Amounts Recognized in the Consolidated Balance Sheets

	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 post-retirement liability[(a)]	$ 38	$ —	$ 31	$ 17	$ 15	$ 2	$ —
Noncurrent post-retirement liability[(b)]	586	64	325	174	149	23	63
Total accrued post-retirement liability	$ 624	$ 64	$ 356	$ 191	$ 164	$ 25	$ 63
Regulatory assets	$ 54	$ —	$ 48	$ 38	$ 10	$ —	$ 51
Regulatory liabilities	$ 174	$ 46	$ —	$ —	$ —	$ 19	$ 71
Accumulated other comprehensive (income) loss							
Deferred income tax liability	$ 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)

	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 post-retirement liability[(a)]	$ 37	$ —	$ 31	$ 16	$ 15	$ 2	$ —
Noncurrent post-retirement liability[(b)]	583	66	323	172	149	25	68
Total accrued post-retirement liability	$ 620	$ 66	$ 354	$ 188	$ 164	$ 27	$ 68
Regulatory assets	$ 1	$ —	$ 1	$ —	$ 1	$ —	$ 57
Regulatory liabilities	$ 288	$ 68	$ 51	$ 25	$ 26	$ 21	$ 83
Accumulated other comprehensive (income) loss							
Deferred income tax liability	$ 7	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(6)	—	(1)	—	—	—	—
Net actuarial gain	(13)	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (12)	$ —	$ (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, 11 years for Duke Energy Carolinas, eight years for Duke Energy Ohio, nine years for Duke Energy Indiana and Duke Energy Kentucky, seven years for Progress Energy and Duke Energy Progress and eight years for Duke Energy Florida.

The following tables present the assumptions used for other post-retirement benefits accounting.

	December 31,		
	2016	**2015**	**2014**
Benefit Obligations			
Discount rate	**4.10%**	4.40%	4.10%
Net Periodic Benefit Cost			
Discount rate	**4.40%**	4.10%	4.70%
Expected long-term rate of return on plan assets	**6.50%**	6.50%	6.75%
Assumed tax rate	**35%**	35%	35%

Assumed Health Care Cost Trend Rate

	December 31,	
	2016	**2015**
Health care cost trend rate assumed for next year	**7.00%**	7.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75%**	4.75%
Year that rate reaches ultimate trend	**2023**	2023

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	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**
1-Percentage Point Increase							
Effect on total service and interest costs	**$ 1**	**$ —**	**$ 1**	**$ 1**	**$ —**	**$ —**	**$ —**
Effect on post-retirement benefit obligation	**29**	**7**	**12**	**6**	**5**	**1**	**3**
1-Percentage Point Decrease							
Effect on total service and interest costs	**(1)**	**—**	**(1)**	**(1)**	**—**	**—**	**—**
Effect on post-retirement benefit obligation	**(25)**	**(6)**	**(10)**	**(6)**	**(5)**	**(1)**	**(2)**

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Years ending December 31,							
2017	$ 85	$ 18	$ 32	$ 17	$ 15	$ 4	$ 10
2018	81	18	31	16	15	3	9
2019	78	18	31	16	14	3	9
2020	75	18	30	16	14	3	8
2021	72	18	29	15	13	3	7
2021 – 2025	310	76	126	67	58	12	31

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. Piedmont also has qualified pension (Piedmont Pension Assets) and other post-retirement assets. 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, 2016 and 2015. 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, 2016, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.50 percent (6.75 percent for Piedmont Pension and OPEB Assets). 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 return. 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 $156 million and $305 million at December 31, 2016 and 2015, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2016 and 2015, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2016, 2015 and 2014, 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, 2016 and the actual asset allocations for the Duke Energy Master Retirement Trust.

	Target Allocation[(a)]	Actual Allocation at December 31, 2016[(a)]	2015
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 have 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 (OPEB Assets) are comprised of Voluntary Employees' Beneficiary Association trusts and mutual funds within a Piedmont 401(h) account (OPEB Assets exclude 401(h) accounts 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 OPEB Assets at December 31, 2016.

	Target Allocation	Actual Allocation at December 31, 2016	2015
U.S. equity securities	38%	**39%**	29%
Real estate	2%	**2%**	—%
Debt securities	45%	**37%**	28%
Cash	15%	**22%**	43%
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 and Piedmont Pension Assets.

	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	—	—
Government and commercial mortgage backed securities	—	—	—	—	—
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 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 are not categorized. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

	December 31, 2015				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized(b)
Equity securities	$ 2,160	$ 1,470	$ 2	$ —	$ 688
Corporate debt securities	4,362	—	4,362	—	—
Short-term investment funds	404	192	212	—	—
Partnership interests	185	—	—	—	185
Hedge funds	210	—	—	—	210
Real estate limited partnerships	118	—	—	—	118
U.S. government securities	748	—	748	—	—
Guaranteed investment contracts	31	—	—	31	—
Governments bonds – foreign	34	—	34	—	—
Cash	10	10	—	—	—
Government and commercial mortgage backed securities	9	—	9	—	—
Net pending transactions and other investments	(28)	(36)	8	—	—
Total assets(a)	$ 8,243	$ 1,636	$ 5,375	$ 31	$ 1,201

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana were allocated approximately 28 percent, 32 percent, 15 percent, 16 percent, 5 percent and 8 percent, respectively, of the Duke Energy Master Retirement Trust assets at December 31, 2015. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments are not categorized. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

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)	2016	2015
Balance at January 1	**$ 31**	$ 34
Combination of Piedmont Pension Assets	**9**	—
Sales	**(2)**	(2)
Total gains (losses) and other, net	**—**	(1)
Balance at December 31	**$ 38**	$ 31

Other post-retirement assets

The following tables provide the fair value measurement amounts for OPEB Assets.

	December 31, 2016			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	**$ 14**	**—**	**$ 14**	**—**
Real estate	**1**	**—**	**1**	**—**
Equity securities	**26**	**—**	**26**	**—**
Debt securities	**25**	**—**	**25**	**—**
Total assets	**$ 66**	**—**	**$ 66**	**—**

	December 31, 2015			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 18	—	$ 18	—
Equity securities	12	—	12	—
Debt securities	12	—	12	—
Total assets	$ 42	—	$ 42	—

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 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**
Years ended December 31,							
2016	**$ 169**	**$ 57**	**$ 50**	**$ 35**	**$ 15**	**$ 3**	**$ 8**
2015	159	54	48	34	13	3	7
2014	143	47	43	30	14	3	7

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 compensation plus an additional 4 percent of 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 three months ended December 31, 2016. In January 2017, a $2.2 million contribution was made to the MPP plan.

22. INCOME TAXES

Income Tax Expense

Components of 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 net operating loss (NOL) carryforwards 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 benefits of NOL carryforwards and utilization of NOL 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.

	Year Ended December 31, 2014						
(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	$ —	$ 161	$ (466)	$ (184)	$ (53)	$ (73)	$ (112)
State	56	51	(8)	14	1	3	1
Foreign	6	—	—	—	—	—	—
Total current income taxes	62	212	(474)	(170)	(52)	(70)	(111)
Deferred income taxes							
Federal	1,144	407	938	436	350	113	294
State	35	(25)	84	25	52	1	15
Total deferred income taxes(a)(b)	1,179	382	1,022	461	402	114	309
Investment tax credit amortization	(16)	(6)	(8)	(6)	(1)	(1)	(1)
Income tax expense from continuing operations	1,225	588	540	285	349	43	197
Tax expense (benefit) from discontinued operations	149	—	(4)	—	—	(300)	—
Total income tax expense (benefit) included in Consolidated Statements of Operations	$ 1,374	$ 588	$ 536	$ 285	$ 349	$ (257)	$ 197

(a) There were no benefits of NOL carryforwards.

(b) Includes utilization of NOL carryforwards of $1,544 million at Duke Energy, $345 million at Duke Energy Carolinas, $530 million at Progress Energy, $291 million at Duke Energy Progress, $64 million at Duke Energy Florida, $56 million at Duke Energy Ohio and $141 million at Duke Energy Indiana.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Domestic	**$ 3,689**	$ 3,831	$ 3,637
Foreign	**45**	79	126
Income from continuing operations before income taxes	**$ 3,734**	$ 3,910	$ 3,763

Taxes on Foreign Earnings

During 2014, Duke Energy declared a taxable dividend of foreign earnings in the form of notes payable that was expected to result in the repatriation of approximately $2.7 billion of cash held, and expected to be generated, by International businesses over a period of up to eight years. As a result of the decision to repatriate cumulative historical undistributed foreign earnings, Duke Energy recorded U.S. income tax expense of approximately $373 million in 2014. As of December 31, 2014, Duke Energy's intention was to indefinitely reinvest any future undistributed 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, 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%

	Year Ended December 31, 2014						
(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	$ 1,317	$ 581	$ 497	$ 263	$ 314	$ 39	$ 195
State income tax, net of federal income tax effect	59	17	49	25	34	3	10
AFUDC equity income	(47)	(32)	(9)	(9)	—	(1)	(5)
Renewable energy production tax credits	(67)	—	—	—	—	—	—
Other items, net	(37)	22	3	6	1	2	(3)
Income tax expense from continuing operations	$ 1,225	$ 588	$ 540	$ 285	$ 349	$ 43	$ 197
Effective tax rate	32.6%	35.4%	38.0%	37.9%	38.9%	38.9%	35.5%

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, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Deferred credits and other liabilities	$ 382	$ 66	$ 126	$ 40	$ 93	$ 21	$ 4
Capital lease obligations	60	8	—	—	—	—	1
Pension, post-retirement and other employee benefits	561	16	199	91	96	22	37
Progress Energy merger purchase accounting adjustments(a)	918	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,682	192	1,165	222	232	49	278
Investments and other assets	—	—	—	—	—	3	—
Other	205	16	35	8	—	5	9
Valuation allowance	(96)	—	(12)	—	—	—	—
Total deferred income tax assets	6,712	298	1,513	361	421	100	329
Investments and other assets	(1,892)	(1,149)	(597)	(313)	(297)	—	(21)
Accelerated depreciation rates	(14,872)	(4,664)	(4,490)	(2,479)	(2,038)	(1,404)	(1,938)
Regulatory assets and deferred debits, net	(4,103)	(1,029)	(1,672)	(892)	(780)	(139)	(270)
Total deferred income tax liabilities	(20,867)	(6,842)	(6,759)	(3,684)	(3,115)	(1,543)	(2,229)
Net deferred income tax liabilities	$ (14,155)	$ (6,544)	$ (5,246)	$ (3,323)	$ (2,694)	$ (1,443)	$ (1,900)

(a) Primarily related to capital lease obligations and debt fair value adjustments.

The following table presents the expiration of tax credits and NOL carryforwards.

	December 31, 2016	
(in millions)	**Amount**	**Expiration Year**
Investment tax credits	$ 1,143	2027 — 2036
Alternative minimum tax credits	1,151	Indefinite
Federal NOL carryforwards	1,267	2020 — 2036
State NOL carryforwards and credits(a)	248	2017 — 2036
Foreign NOL carryforwards(b)	12	2026 — 2036
Foreign Tax Credits	859	2024 — 2026
Charitable Carryforwards	2	2017 — 2019
Total tax credits and NOL carryforwards	$ 4,682	

(a) A valuation allowance of $84 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 $12 million has been recorded on the foreign NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

	December 31, 2015						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Deferred credits and other liabilities	$ 201	$ 38	$ 115	$ 25	$ 66	$ 29	$ 5
Capital lease obligations	63	9	—	—	—	—	2
Pension, post-retirement and other employee benefits	580	46	186	92	82	24	40
Progress Energy merger purchase accounting adjustments(a)	1,009	—	—	—	—	—	—
Tax credits and NOL carryforwards	3,631	170	997	163	177	25	215
Investments and other assets	—	—	—	—	—	3	—
Other	206	20	48	2	46	37	20
Valuation allowance	(93)	—	(38)	—	—	—	—
Total deferred income tax assets	5,597	283	1,308	282	371	118	282
Investments and other assets	(1,573)	(1,057)	(412)	(228)	(201)	—	(7)
Accelerated depreciation rates	(12,939)	(4,429)	(4,169)	(2,325)	(1,868)	(1,356)	(1,797)
Regulatory assets and deferred debits, net	(3,633)	(943)	(1,517)	(756)	(762)	(169)	(135)
Total deferred income tax liabilities	(18,145)	(6,429)	(6,098)	(3,309)	(2,831)	(1,525)	(1,939)
Net deferred income tax liabilities	$ (12,548)	$ (6,146)	$ (4,790)	$ (3,027)	$ (2,460)	$ (1,407)	$ (1,657)

(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 recorded a net reduction of approximately $95 million to its North Carolina deferred tax liability in the third quarter of 2015. 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 and Duke Energy Progress. 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 recorded a net reduction of approximately $80 million to its North Carolina deferred tax liability 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 and Duke Energy Progress. 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, 2016					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**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**	**—**
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**	**(1)**
Unrecognized tax benefits – December 31	**$ 17**	**$ 1**	**$ 2**	**$ 2**	**$ 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

	Year Ended December 31, 2014					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Indiana**
Unrecognized tax benefits – January 1	$ 230	$ 171	$ 32	$ 22	$ 8	$ 1
Unrecognized tax benefits increases (decreases)						
Gross increases — tax positions in prior periods	—	—	1	1	—	—
Gross decreases – tax positions in prior periods	(2)	—	—	—	—	—
Decreases due to settlements	(15)	(11)	(1)	—	—	—
Total changes	(17)	(11)	—	1	—	—
Unrecognized tax benefits – December 31	$ 213	$ 160	$ 32	$ 23	$ 8	$ 1

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits. It is reasonably possible that Duke Energy could reflect an approximate $8 million reduction and Duke Energy Carolinas could reflect an approximate $1 million reduction in unrecognized tax benefits within the next 12 months. All other Duke Energy Registrants do not anticipate a material increase or decrease in unrecognized tax benefits within the next 12 months.

	December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	$ 8	$ 1	$ 2	$ 2	$ —	$ —	$ —
Amount that if recognized, would be recorded as a component of discontinued operations	5	—	—	—	—	2	—

(a) Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana 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, 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	—	—

	Year Ended December 31, 2014						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Net interest income recognized related to income taxes	$ 6	$ —	$ 3	$ —	$ 1	$ 4	$ 4
Net interest expense recognized related to income taxes	—	1	—	1	—	—	—
Interest receivable related to income taxes	—	—	—	—	—	—	2
Interest payable related to income taxes	13	13	5	3	5	—	—

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 2004.

23. OTHER INCOME AND EXPENSES, NET

The components of Other income and expenses, net on the Consolidated Statements of Operations are as follows.

	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
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

	Year Ended December 31, 2014						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Interest income	$ 16	$ 4	$ 3	$ —	$ 2	$ 8	$ 6
AFUDC equity	135	91	26	25	—	4	14
Post in-service equity returns	89	71	17	17	—	—	—
Nonoperating income (expense), other	80	6	31	9	18	(2)	2
Other income and expense, net	$ 320	$ 172	$ 77	$ 51	$ 20	$ 10	$ 22

24. SUBSEQUENT EVENTS

For information on subsequent events related to regulatory matters, commitments and contingencies, and debt and credit facilities see Notes 4, 5 and 6, 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
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**
2015					
Operating revenues	$ 5,792	$ 5,302	$ 6,202	$ 5,075	$ 22,371
Operating income	1,390	1,192	1,606	890	5,078
Income from continuing operations	755	576	890	433	2,654
Income (Loss) from discontinued operations, net of tax	112	(29)	45	49	177
Net income	867	547	935	482	2,831
Net income attributable to Duke Energy Corporation	864	543	932	477	2,816
Earnings per share:					
Income from continuing operations attributable to Duke Energy Corporation common stockholders					
Basic	$ 1.06	$ 0.83	$ 1.29	$ 0.62	$ 3.80
Diluted	$ 1.06	$ 0.83	$ 1.29	$ 0.62	$ 3.80
Income (Loss) from discontinued operations attributable to Duke Energy Corporation common stockholders					
Basic	$ 0.16	$ (0.05)	$ 0.06	$ 0.07	$ 0.25
Diluted	$ 0.16	$ (0.05)	$ 0.06	$ 0.07	$ 0.25
Net income attributable to Duke Energy Corporation common stockholders					
Basic	$ 1.22	$ 0.78	$ 1.35	$ 0.69	$ 4.05
Diluted	$ 1.22	$ 0.78	$ 1.35	$ 0.69	$ 4.05

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
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)**
2015					
Costs to Achieve Mergers	$ (21)	$ (22)	$ (24)	$ (30)	$ (97)
Edwardsport Settlement (see Note 4)	—	—	(90)	(3)	(93)
Ash Basin Settlement and Penalties (see Note 5)	—	—	(7)	(7)	(14)
State Tax Adjustment related to Midwest Generation Sale	—	(41)	—	—	(41)
Cost Savings Initiatives (see Note 19)	—	—	—	(142)	(142)
Total	$ (21)	$ (63)	$ (121)	$ (182)	$ (387)

DUKE ENERGY CAROLINAS

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
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**
2015					
Operating revenues	$ 1,901	$ 1,707	$ 2,061	$ 1,560	$ 7,229
Operating income	515	483	666	296	1,960
Net income	292	265	383	141	1,081

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
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)**
2015					
Costs to Achieve Mergers	$ (9)	$ (11)	$ (11)	$ (16)	$ (47)
Ash Basin Settlement and Penalties (see Note 5)	—	—	(1)	(7)	(8)
Cost Savings Initiatives (see Note 19)	—	—	—	(93)	(93)
Total	$ (9)	$ (11)	$ (12)	$ (116)	$ (148)

PROGRESS ENERGY

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
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**
2015					
Operating revenues	$ 2,536	$ 2,476	$ 2,929	$ 2,336	$ 10,277
Operating income	549	504	756	351	2,160
Income from continuing operations	264	217	452	132	1,065
Net income	263	217	451	131	1,062
Net income attributable to Parent	260	215	448	128	1,051

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
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)**
2015					
Costs to Achieve Mergers	$ (8)	$ (8)	$ (8)	$ (10)	$ (34)
Ash Basin Settlement and Penalties (see Note 5)	—	—	(6)	—	(6)
Cost Savings Initiatives (see Note 19)	—	—	—	(36)	(36)
Total	$ (8)	$ (8)	$ (14)	$ (46)	$ (76)

DUKE ENERGY PROGRESS

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
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**
2015					
Operating revenues	$ 1,449	$ 1,193	$ 1,488	$ 1,160	$ 5,290
Operating income	316	184	394	130	1,024
Net income	183	85	229	69	566

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
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)**
2015					
Costs to Achieve Mergers	$ (5)	$ (5)	$ (6)	$ (6)	$ (22)
Ash Basin Settlement and Penalties (see Note 5)	—	—	(6)	—	(6)
Cost Savings Initiatives (see Note 19)	—	—	—	(28)	(28)
Total	$ (5)	$ (5)	$ (12)	$ (34)	$ (56)

DUKE ENERGY FLORIDA

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
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**
2015					
Operating revenues	$ 1,086	$ 1,281	$ 1,436	$ 1,174	$ 4,977
Operating income	227	315	357	216	1,115
Net income	113	165	216	105	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
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)**
2015					
Costs to Achieve Mergers	$ (3)	$ (3)	$ (3)	$ (4)	$ (13)
Cost Savings Initiatives (see Note 19)	—	—	—	(8)	(8)
Total	$ (3)	$ (3)	$ (3)	$ (12)	$ (21)

DUKE ENERGY OHIO

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
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**
2015					
Operating revenues	$ 586	$ 405	$ 462	$ 452	$ 1,905
Operating income	111	43	76	73	303
Income (Loss) from discontinued operations, net of tax	90	(65)	(2)	—	23
Net income (loss)	149	(52)	32	43	172

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
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)**
2015					
Costs to Achieve Mergers	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)
Cost Savings Initiatives (see Note 19)	—	—	—	(2)	(2)
Total	$ (1)	$ (1)	$ (1)	$ (3)	$ (6)

DUKE ENERGY INDIANA

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2016					
Operating revenues	**$ 714**	**$ 702**	**$ 809**	**$ 733**	**$ 2,958**
Operating income	**176**	**174**	**239**	**176**	**765**
Net income	**95**	**85**	**129**	**72**	**381**
2015					
Operating revenues	$ 788	$ 686	$ 749	$ 667	$ 2,890
Operating income	210	146	117	171	644
Net income	108	68	46	94	316

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
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)**
2015					
Costs to Achieve Mergers	$ (2)	$ (1)	$ (2)	$ (2)	$ (7)
Edwardsport Settlement (see Note 4)	—	—	(90)	(3)	(93)
Cost Savings Initiatives (see Note 19)	—	—	—	(6)	(6)
Total	$ (2)	$ (1)	$ (92)	$ (11)	$ (106)

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	04/13/2017	End of 2016/Q4

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				

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	04/13/2017	End of 2016/Q4

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		(257,076)	(257,076)	[redacted]	[redacted]
2		24,819	24,819	[redacted]	[redacted]
3				[redacted]	[redacted]
4		24,819	24,819	566,483,807	566,508,626
5		(232,257)	(232,257)	[redacted]	[redacted]
6		(232,257)	(232,257)	[redacted]	[redacted]
7		25,611	25,611	[redacted]	[redacted]
8				[redacted]	[redacted]
9		25,611	25,611	599,400,762	599,426,373
10		(206,646)	(206,646)	[redacted]	[redacted]

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	04/13/2017	End of 2016/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)	22,690,518,332	22,690,518,332
4	Property Under Capital Leases	141,917,584	141,917,584
5	Plant Purchased or Sold		
6	Completed Construction not Classified	3,291,160,150	3,291,160,150
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	26,123,596,066	26,123,596,066
9	Leased to Others		
10	Held for Future Use	43,226,314	43,226,314
11	Construction Work in Progress	1,303,611,534	1,303,611,534
12	Acquisition Adjustments	349,801,943	349,801,943
13	Total Utility Plant (8 thru 12)	27,820,235,857	27,820,235,857
14	Accum Prov for Depr, Amort, & Depl	11,379,160,840	11,379,160,840
15	Net Utility Plant (13 less 14)	16,441,075,017	16,441,075,017
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	11,088,222,152	11,088,222,152
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	272,863,816	272,863,816
22	Total In Service (18 thru 21)	11,361,085,968	11,361,085,968
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	18,074,872	18,074,872
33	Total Accum Prov (equals 14) (22,26,30,31,32)	11,379,160,840	11,379,160,840

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	04/13/2017	End of 2016/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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					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	04/13/2017	End of 2016/Q4

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	17,008,248	33,273,439
3	Nuclear Materials	306,264,190	180,636,613
4	Allowance for Funds Used during Construction	14,493,593	8,889,213
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	337,766,031	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		249,547,827
9	In Reactor (120.3)	822,011,827	186,755,739
10	SUBTOTAL (Total 8 & 9)	822,011,827	
11	Spent Nuclear Fuel (120.4)	206,799,870	172,156,451
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	644,547,755	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	722,029,973	
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)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	35,715,460	14,566,227	2
	203,787,701	283,113,102	3
	10,044,666	13,338,140	4
			5
		311,017,469	6
			7
	186,755,739	62,792,088	8
	172,156,451	836,611,115	9
		899,403,203	10
	108,964,282	269,992,039	11
			12
-198,154,417	112,695,762	730,006,410	13
		750,406,301	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 $108,964,282 of nuclear fuel assemblies retired from the reactor and $3,731,480 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	04/13/2017	End of 2016/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	44,632,410	10,519,916
4	(303) Miscellaneous Intangible Plant	341,326,052	16,609,597
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	386,718,856	27,129,513
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	29,073,917	
9	(311) Structures and Improvements	604,597,217	-114,787,217
10	(312) Boiler Plant Equipment	2,401,238,238	191,385,438
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	367,084,485	5,769,399
13	(315) Accessory Electric Equipment	241,016,900	9,254,690
14	(316) Misc. Power Plant Equipment	59,614,321	7,491,509
15	(317) Asset Retirement Costs for Steam Production	934,027,036	144,640,450
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,636,652,114	243,754,269
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	68,332,963	27,864
19	(321) Structures and Improvements	2,864,307,050	105,895,565
20	(322) Reactor Plant Equipment	2,369,716,452	97,710,902
21	(323) Turbogenerator Units	911,922,772	65,316,761
22	(324) Accessory Electric Equipment	979,564,608	59,077,965
23	(325) Misc. Power Plant Equipment	504,846,656	52,783,035
24	(326) Asset Retirement Costs for Nuclear Production	876,137,782	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	8,574,828,283	380,812,092
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	2,778,049	
28	(331) Structures and Improvements	11,295,160	257,434
29	(332) Reservoirs, Dams, and Waterways	46,708,240	2,069,794
30	(333) Water Wheels, Turbines, and Generators	30,352,671	227,612
31	(334) Accessory Electric Equipment	7,670,174	17,972,798
32	(335) Misc. Power PLant Equipment	3,994,402	118,133
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)	103,356,818	20,645,771
36	D. Other Production Plant		
37	(340) Land and Land Rights	8,706,635	
38	(341) Structures and Improvements	308,323,429	5,124,526
39	(342) Fuel Holders, Products, and Accessories	118,786,383	1,340,872
40	(343) Prime Movers	1,792,186,678	135,146,031
41	(344) Generators	406,838,334	63,351,841
42	(345) Accessory Electric Equipment	302,921,510	9,972,376
43	(346) Misc. Power Plant Equipment	42,403,522	3,772,041
44	(347) Asset Retirement Costs for Other Production	12,401,317	2,614,574
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,992,567,808	221,322,261
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	16,307,405,023	866,534,393

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	04/13/2017	End of 2016/Q4

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	185,282,630	-149,179
49	(352) Structures and Improvements	96,697,071	11,037,023
50	(353) Station Equipment	934,046,264	41,512,590
51	(354) Towers and Fixtures	78,756,611	-13,082,117
52	(355) Poles and Fixtures	634,385,711	34,075,713
53	(356) Overhead Conductors and Devices	401,669,475	64,441,286
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	21,550,998	53,001
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)	2,352,701,283	137,888,317
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	63,238,102	-1,628,010
61	(361) Structures and Improvements	102,429,953	2,976,837
62	(362) Station Equipment	547,824,748	38,228,649
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	703,070,806	37,674,145
65	(365) Overhead Conductors and Devices	923,774,939	124,602,743
66	(366) Underground Conduit	180,092,360	8,523,362
67	(367) Underground Conductors and Devices	1,006,802,377	30,135,495
68	(368) Line Transformers	888,832,433	100,806,925
69	(369) Services	493,857,289	33,220,318
70	(370) Meters	210,536,277	1,169,648
71	(371) Installations on Customer Premises	284,056,435	-3,359,480
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	156,656,945	45,396,476
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,561,172,664	417,747,108
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	7,883,410	702,115
87	(390) Structures and Improvements	140,498,257	9,763,032
88	(391) Office Furniture and Equipment	58,723,652	6,213,823
89	(392) Transportation Equipment	117,049,626	1,978,554
90	(393) Stores Equipment	3,748,743	221,353
91	(394) Tools, Shop and Garage Equipment	41,910,740	7,967,707
92	(395) Laboratory Equipment	12,379,707	1,883,360
93	(396) Power Operated Equipment	2,964,553	685,561
94	(397) Communication Equipment	246,145,005	3,546,810
95	(398) Miscellaneous Equipment	27,210,663	340,596
96	SUBTOTAL (Enter Total of lines 86 thru 95)	658,514,356	33,302,911
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)	661,231,944	33,302,911
100	TOTAL (Accounts 101 and 106)	25,269,229,770	1,482,602,242
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)	25,269,229,770	1,482,602,242

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
			55,152,326		3
5,502,042			352,433,607		4
5,502,042			408,346,327		5
					6
					7
13,747		-1,292,549	27,767,621		8
465,764			489,344,236		9
17,366,810			2,575,256,866		10
					11
6,634,483			366,219,401		12
1,308,835			248,962,755		13
2,162,602			64,943,228		14
252,141,891			826,525,595		15
280,094,132		-1,292,549	4,599,019,702		16
					17
			68,360,827		18
37,201,381	-27,685	533,134	2,933,506,683		19
27,846,190			2,439,581,164		20
3,135,811			974,103,722		21
15,955,703		-533,134	1,022,153,736		22
2,095,903			555,533,788		23
			876,137,782		24
86,234,988	-27,685		8,869,377,702		25
					26
		50,868	2,828,917		27
3,657			11,548,937		28
280,239			48,497,795		29
-813			30,581,096		30
23,438			25,619,534		31
105,945			4,006,590		32
			21,205		33
			536,917		34
412,466		50,868	123,640,991		35
					36
4,919		1,292,549	9,994,265		37
214,745	-1,916,098		311,317,112		38
959,218			119,168,037		39
73,958,753			1,853,373,956		40
3,676,955			466,513,220		41
4,639,714			308,254,172		42
1,859,306			44,316,257		43
			15,015,891		44
85,313,610	-1,916,098	1,292,549	3,127,952,910		45
452,055,196	-1,943,783	50,868	16,719,991,305		46

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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
1,407		-2,331,455	182,800,589		48
200,712	-155,534		107,377,848		49
4,488,906		132,947	971,202,895		50
-1,369		-4,590,926	61,084,937		51
587,059		5,735,716	673,610,081		52
281,335		-1,160,903	464,668,523		53
					54
			21,603,999		55
			312,523		56
					57
5,558,050	-155,534	-2,214,621	2,482,661,395		58
					59
75,140		2,414,886	63,949,838		60
162,736		-18,320	105,225,734		61
3,598,679		242,931	582,697,649		62
					63
7,267,643			733,477,308		64
11,710,230		16,113	1,036,683,565		65
293,477			188,322,245		66
2,462,071			1,034,475,801		67
9,367,508			980,271,850		68
36,512,158			490,565,449		69
12,018,340			199,687,585		70
1,744,187			278,952,768		71
					72
10,088,046			191,965,375		73
					74
95,300,215		2,655,610	5,886,275,167		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
571,779		-50,868	7,962,878		86
8,955,940	-97,936	18,320	141,225,733		87
9,100,695			55,836,780		88
17,549,540			101,478,640		89
377,234			3,592,862		90
			49,878,447		91
7,031,514			7,231,553		92
280,569			3,369,545		93
23,537,572			226,154,243		94
677,656			26,873,603		95
68,082,499	-97,936	-32,548	623,604,284		96
					97
			2,717,588		98
68,082,499	-97,936	-32,548	626,321,872		99
626,498,002	-2,197,253	459,309	26,123,596,066		100
					101
					102
					103
626,498,002	-2,197,253	459,309	26,123,596,066		104

Schedule Page: 204 Line No.: 15 Column: g

Asset Retirement Cost Steam Additions relate primarily to Q3 & Q4 2016 revisions made to AROs related to the CCR Rule and North Carolina Coal Ash Management Act (CAMA). Asset Retirement Cost Steam Retirements primarily relate to additions and revisions related to CCR and CAMA at retired plants.

Schedule Page: 204 Line No.: 19 Column: e

Adjustment includes reduction of the Harris E&E Center capital lease portion attributable to nuclear plant.

Schedule Page: 204 Line No.: 38 Column: e

Adjustment includes reduction of the Wayne County Pipeline capital lease portion attributable to other production plant.

Schedule Page: 204 Line No.: 44 Column: g

Asset Retirement Cost Other Production Additions relate to the recognition of one new ARO for regulated solar facilities.

Schedule Page: 204 Line No.: 49 Column: e

Adjustment includes reduction of the NCEMC Network Integration Transmission Service Agreement (NITSA) capital lease portion attributable to transmission plant.

Schedule Page: 204 Line No.: 87 Column: e

Adjustment includes reduction of the HQ Building capital lease portion attributable to general 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	04/13/2017	End of 2016/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					
2					
3					
4					
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6					
7					
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9					
10					
11					
12					
13					
14					
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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	04/13/2017	End of 2016/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	Lee - Plant Selma 115kv Line	03/2010	2025	416,389
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	Cape Fear - Silver City 230kv Line	10/2009	2023	4,456,348
7	Garner East 230kv Substation Land Purchase	05/2011	2023	3,610,841
8	Mayo Fossil - Future Land - Ash Pond	12/1983	2020	1,458,908
9	Sanford South Distribution Substation	06/2013	2017	350,441
10	Weatherspoon IC - Future Generation Addition	07/2008	2018	633,647
11	Jacksonville - Blue Creek 115kV Substation	11/2016	2017	2,280,331
12	Onslow County - Grant's Creek 230kV Line	12/2016	2020	991,126
13	Jacksonville - Grant's Creek 230kv Line	09/2014	2020	1,122,763
14	McDowell Street Substation - Buncombe County	07/2013	2021	5,554,452
15	Ashville - Elm Street 115kv Substation	09/2016	2018	2,967,744
16	Carven Street Substation - Buncombe County	07/2013	2020	5,290,411
17	McDowell Street Substation - Missions Hospital	09/2015	2020	2,171,148
18	Porter's Neck 230kv Substation	10/2016	2023	8,260,423
19				
20	Other Land and Rights < $250K (13 Items)			660,775
21	Other Property:			
22				
23				
24				
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42				
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44				
45				
46				
47	Total			43,226,314

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	04/13/2017	End of 2016/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	INSTALL NEW SERVICE AT GRAMACY APARTMENTS	1,038,257
4	CITY OF RALEIGH LED RETROFIT	10,978,931
5	TOWN OF WILMINGTON LED UPGRADE	1,492,692
6	FUQUAY BROADWAY 115KV SUBSTATION	1,959,115
7	INCREASE CAPACITY MOREHEAD CITY 115KV SUBSTATION	1,284,404
8	CONSTRUCT JACKSONVILLE SOUTH 115KV SUBSTATION	2,564,002
9	BILTMORE 115KV CAPACITY INCREASE	1,063,493
10	SANFORD SOUTH DISTRIBUTION PROJECT	2,356,418
11	REMOVE AND REPLACE CLEVELAND RD 24KV BREAKER	1,172,995
12	DOWNTOWN RALEIGH DISTRIBUTION AUTOMATION	2,209,728
13	SG DEP DOWNTOWN UNDERGROUND	1,004,752
14	PROJECTS LESS THAN $1 MILLION	29,929,272
15	TOTAL DISTRIBUTION PLANT $57,054,059	
16		
17	GENERAL PLANT	
18		
19	NEW GROUNDING EQUIPMENT - CAROLINAS EAST	1,317,900
20	CARY-LINE & SERVICE BLDG	1,054,313
21	FLORENCE-NEW GARAGE	1,312,501
22	WILMINGTON EASTERN REGION OFFICE	1,043,125
23	NEW WAREHOUSE BUILDING RALEIGH NC	3,633,787
24	PROJECTS LESS THAN $1 MILLION	16,774,127
25	TOTAL GENERAL PLANT $25,135,753	
26		
27	INTANGIBLE PLANT	
28		
29	SMARTGEN SYSTEM	4,018,997
30	PEC PRIMAVERA SOFTWARE	7,022,540
31	ENABLE SOFTWARE	28,472,667
32	CAROLINAS EMS CONSOLIDATION	2,523,677
33	DAILY RATING CHARGING ESTIMATE TOOL	4,908,527
34	ELECTRONIC WORK PACKAGE APPLICATION	2,153,779
35	INTERVAL BASED MAJOR MAINTENANCE OPTIMIZATION MODELING TOOL	1,027,958
36	MWMS CONSOLIDATION	4,432,969
37	SG DMS CONSOLIDATION - TED THOMAS TOWER	1,450,649
38	DMS PROJECT 3	2,054,723
39	REPLACE EXISTING TOA SOFTWARE	1,452,991
40	PROJECTS LESS THAN $1 MILLION	4,561,989
41	TOTAL INTANGIBLE PLANT $64,081,466	
42		
43	TOTAL	1,303,611,534

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	04/13/2017	End of 2016/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	PRODUCTION PLANT	
2		
3	BLEWETT UNIT 4 GENERATOR REWIND	1,918,794
4	BLEWETT FERC INSTPECTION FOLLOW-UP ACTIVITIES	3,287,854
5	IMPLEMENTATION OF NEW LICENSE REQUIREMENTS	5,471,960
6	BLEWETT INSTALL NEUTRAL GROUNDING RELAY REPLACEMENT	1,165,181
7	BRUNSWICK FEEDWATER HEATER REPLACEMENT	3,352,079
8	BRUNSWICK PA CAMERA REPLACEMENT	2,094,856
9	BRUNSWICK UNIT 1 CW PUMP REPLACEMENT	4,577,817
10	BRUNSWICK UNIT 1 FEEDWATER HEATER REPLACEMENT	1,852,879
11	BRUNSWICK SERVICE WATER PUMP REPLACEMENT	3,737,873
12	BRUNSWICK SALT WATER - PUMP REPLACEMENT	5,746,106
13	BRUNSWICK UNIT 1 REACTOR BUILDING ROOF DRAIN ISOLATION VALVES	4,042,177
14	BRUNSWICK UNIT 1 HEAT EXCHANGER REPLACEMENT	1,408,099
15	BRUNSWICK UNIT 2 REACTOR BUILDING ROOF DRAIN REPLACEMENT	3,185,917
16	BRUNSWICK UNIT 1 ASCOM MINI-CELL PHASE 2	2,823,806
17	BRUNSWICK UNIT 2 REACTOR REFUEL BRIDGE CRANE	1,777,837
18	BRUNSWICK MOV SHOP REPLACEMENT	1,281,793
19	BRUNSWICK NEW INSULATION SHOP	1,376,827
20	BRUNSWICK UNIT 1 TURBINE GIRDER REPLACEMENT	1,979,258
21	BRUNSWICK EMERGENCY WASTE PROCESSING SKID	1,784,507
22	EMERGENCY PREPAREDNESS NETWORK	1,691,769
23	BRUNSWICK OPEN PHASE FAULT DETECTION	3,842,403
24	BRUNSWICK OPEN PHASE FAULT DETECTION	2,768,843
25	HARRIS SYSTEM REPLACEMENT	12,938,696
26	ROBINSON CONDENSATE POLISHING DCS	2,674,089
27	ROBINSON MAKE-UP WATER TREATMENT DCS	1,478,339
28	HARRIS FIRE DETECTION SYSTEM UPGRADE - MASTER	3,768,706
29	BRUNSWICK UNIT 2 MOISTURE SEPARATER REHEATER REPLACEMENT	2,230,312
30	TURBINE LUBE OIL CONDITIONER REPLACEMENT	1,229,941
31	HARRIS POWER UPRATE	48,212,430
32	ROBINSON HAGAN UPGRADE PART 2	1,268,983
33	ROBINSON MAIN GENERATOR STATOR REWIND	30,135,421
34	BRUNSWICK UNIT 1 EMERGENCY DIESEL GENERATOR UPGRADES & REPLACEMENT	2,730,647
35	BRUNSWICK UNIT 1 EMERGENCY DIESEL GENERATOR UPGRADES & REPLACEMENT	1,025,979
36	BRUNSWICK UNIT 1 EMERGENCY DIESEL GENERATOR UPGRADES & REPLACEMENT	7,192,404
37	BRUNSWICK UNIT 1 EMERGENCY DIESEL GENERATOR UPGRADES & REPLACEMENT	4,861,311
38	BRUNSWICK MELLA PLUS	14,812,213
39	BRUNSWICK UNIT 2 FW HEATER 4&5 VALVE UPGRADE MASTER	8,708,454
40	HARRIS PERIMETER INTRUSION DETECTION REPLACEMENT	17,337,968
41	ROBINSON START-UP TRANSFORMER	4,292,521
42	BRUNSWICK INTRUSION DETECT	24,658,852
43	TOTAL	1,303,611,534

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 TRAVEL SCR INSTR IMPROVEMENT	3,481,189
2	ROBINSON TRANSMISSION UPGRADE	3,347,321
3	BRUNSWICK UNIT 2 TURBINE CRANE UPGRADE	1,961,300
4	ROBINSON UNDER VESSEL INSULATION	2,004,048
5	BRUNSWICK UNIT 1 FW HEATER 4 & 5 LEVEL CONTROL VALVE UPGRADE	9,878,172
6	SAFETY RELATED BATTERY CHARGERS	3,896,632
7	SAFETY RELATED BATTERY CHARGERS	4,657,543
8	BRUNSWICK UNIT 1 MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	41,759,650
9	BRUNSWICK UNIT 1 MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	17,304,620
10	BURNSWICK UNIT 2 MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	9,990,545
11	BURNSWICK UNIT 2 MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	3,602,794
12	HARRIS MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	44,942,055
13	HARRIS MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	7,167,155
14	ROBINSON UNIT 2 MAIN TURBINE GOVERNOR CONTROL SYSTEM UPGRADE	37,056,213
15	BRUNSWICK REACTOR PRESSURE VESSEL HEAD CAROUSEL	1,846,270
16	BRUNSWICK RADIO SYSTEM UPGRADE	6,406,984
17	ROBINSON REPLACE OBSOLETE MOTOR CONTROL CIRCUIT BREAKERS	4,875,469
18	BRUNSWICK UNIT 1 ALT DECAY PRI HEAT	10,358,986
19	HARRIS VESSEL HEAD REPLACE (ALLOY 600)	24,741,647
20	REPLACE SAFETY RELATED CHILLERS	5,424,950
21	POLAR CRANE REMOTE CTROL UPGRADE	2,673,754
22	HARRIS DISTRIBUTED I&C SYSTEM PLATFORM UPGRADE	25,842,941
23	VOICE SYSTEM REPLACEMENT	1,476,897
24	4KV BREAKER REPLACEMENT	2,757,199
25	ROBINSON PENETRATION D-5 TEMP POWER	1,001,539
26	BRUNSWICK PERIMETER INTRUSION DET	4,595,348
27	BRUNSWICK UNIT 1 FLEET REFUEL BRIDGE CRANE REPLACEMENT	3,879,587
28	BRUNSWICK UNIT 2 TRAVEL SCREEN INSRUMENT IMPROVEMENT	3,730,157
29	BRUNSWICK UNIT 1 - 5.1 MARK I/MARK II HARDENED VENTS	2,806,149
30	BRUNSWICK UNIT 2 - 5.1 MARK I/MARK II HARDENED VENTS	7,057,627
31	BRUNSWICK UNIT 1 REMOTE ELECTRIC LIFT & TRAVERSING CRANE	1,182,658
32	BRUNSWICK TURBINE BUILDING AIR WASH CHEMICAL INJECTION SYSTEM	1,058,533
33	HARRIS HEATER DRAIN SYSTEM TO DCS	3,559,321
34	BRUNSWICK UNIT 2 SATELITE REDUCTION	2,194,643
35	ROBINSON NUCLEAR UTILITY SERVICES HAGAN REPLACEMENT	1,813,667
36	ROBINSON DISTRIBUTED I&C SYSTEM PLATFORM UPGRADE	18,915,461
37	ROBINSON PROCESS COMPUTERS	2,821,968
38	BRUNSWICK UNIT 1 DISTRIBUTED I&C SYSTEM PLATFORM UPGRADE	9,941,282
39	BRUNSWICK UNIT 2 DISTRIBUTED I&C SYSTEM PLATFORM UPGRADE	17,887,476
40	BRUNSWICK CASWELL BEACH MICROWAVE TOWER	1,114,984
41	ROBINSON 805 DETECTION&SUPPRESSION	5,746,264
42	HARRIS 6.9KV BREAKERS	1,512,510
43	TOTAL	1,303,611,534

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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 UNIT 1 CHLORINATION IMPROVEMENT	1,465,957
2	BRUNSWICK UNIT 2 CHLORINATION IMPROVEMENT	4,355,041
3	BRUNSWICK REPLACE EMERGENCY DIESEL FUEL TANK VENTS	1,355,520
4	BRUNSWICK TRANSFER EQUIPMENT	2,897,678
5	BRUNSWICK HSM PURCH 2016	8,157,022
6	BRUNSWICK SAW DUST BUILDING REPLACEMENT	1,690,751
7	PLANT PROCESS COMPUTER	2,828,106
8	BRUNSWICK UNIT 2 PPC/ERFIS SOFTWARE UPGRADE	10,389,773
9	BRUNSWICK PBX SYSTEM	3,801,974
10	ROBINSON NB160 SECURITY SYSTEM FENCE	9,037,198
11	HARRIS DRY WET STORAGE	3,379,956
12	UPGRADE HARRIS RADWASTE DEMIN SYSTEM	1,467,224
13	HARRIS EMERGENCY PREPAREDNESS NETWORK	1,527,335
14	HARRIS DIESEL GENERATOR MAINTENANCE BUILDING	2,525,912
15	HARRIS PLANT DATA NETWORK CYBER INTRUSION DETECTION & REPORTING	1,007,161
16	HARRIS EMERGENCY SERVICE WATER PUMP INSTALLATION	1,336,659
17	HARRIS HOT MACHINE SHOP EQUIPMENT REPLACEMENT	1,496,796
18	HARRIS OPEN PHASE DETECTION	4,658,719
19	ADDITIONAL FIBER OPTIC INFRASTRUCTURE	1,735,038
20	REACTOR VESSEL TENSIONERS	2,661,025
21	ROBINSON NFPA 805 IMPLEMENTATION	20,719,347
22	ROBINSON 115 TRANSMISSION SUT	32,427,986
23	ROBINSON NON WEST MCCB REPLACEMENT	1,357,675
24	ROBINSON NON WEST MCCB REPLACEMENT	6,242,172
25	ROBINSON MAIN TURBINE BLADE REPLACEMENT	2,343,284
26	ROBINSON RCCA AGE MANAGEMENT	1,026,629
27	ROBINSON CYBER COMPLIANCE	1,350,078
28	ROBINSON FREEZE PROTECTION	5,046,803
29	ASHEVILLE COMBINED CYCLE	78,109,410
30	SUTTON BLACKSTART COMBUSTION TURBINE PROJECT	72,450,767
31	SMART M&D ADVANCED SENSOR INSTALLATION AT HF LEE	1,269,402
32	HF LEE INSTALL CONDENSER TUBE CLEAN SYSTEM	1,507,827
33	SMITH ENERGY COMPLEX SMARTGEN ADVANCED SENSOR INSTALLATION PROJECT	1,515,784
34	ROXBORO DRY BOTTOM ASH CONVERSION PROJECT	11,823,960
35	ROXBORO UNIT 4 DRY FLY ASH RELIABILITY PROJECT	12,935,457
36	COAL BURNER REPLACEMENT	4,249,195
37	MAYO FUEL GAS DESULFURIZATION WASTEWATER TREATMENT	1,343,804
38	MAYO STORM & PROCESS WATER REROUTE	1,364,596
39	MAYO CONSTRUCT NEW LINED RETENTION BASIN	1,064,777
40	CONSTRUCT CENTERAL CHEMICAL & USED OIL STORAGE	1,358,344
41	ROXBORO FUEL GAS DESULFURIZATION WASTEWATER TREATMENT	5,753,629
42	ROXBORO FGD DCS EVERGREEN UP&IO RPL	1,556,372
43	TOTAL	1,303,611,534

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	ROXBORO TANK FARM VAPR SUPPRESSION SYSTEM	1,006,856
2	ROXBORO ESP MODIFICATIONS	2,764,871
3	ROXBORO DCS EVERGREEN UP&I/O RPL	1,446,969
4	PROJECTS LESS THAN $1 MILLION	81,752,654
5	TOTAL PRODUCTION PLANT $1,040,562,902	
6		
7	TRANSMISSION PLANT	
8		
9	ASHEVILLE COMBINED CYCLE	4,297,081
10	ASHEVILLE COMBINED CYCLE	3,965,548
11	ADDITIONAL CAPACITY FOUR OAKS BUSINESS PARK	2,635,156
12	PERSON 500KV SUB-REPLACE SLY RELAYS ON ROX PLT MID AND ROX PLT HYCO 230 LINES	1,316,462
13	WESTERN CAROLINAS RELIABILITY ENCHANCEMENT PROJECT- PHASE 2C	5,458,619
14	GARNER PANTHER BRANCH 230kV-ADD 2ND BANK	5,727,356
15	GARNER PANTHER BRANCH 230kV-ADD 2ND BANK	3,158,201
16	PRINCETION 115KV-REPLACE S&C MARK II CIRCUIT SWITCHERS	2,260,573
17	LAURINBURG 230KV REPLACE POOR CONDITION TRANSFORMERS	2,940,944
18	SEAGROVE 115KV SUB-REBUILD STATION	1,208,553
19	SUTTON FAST START CT UPGRADE	2,239,506
20	PURCHASE OF MATS	9,715,867
21	INI-TDPLAN - RECONDUCTOR 2.69 MI VANDERBILT-W ASHEVILLE	1,662,879
22	CAPE FEAR SILER CITY 230 (MASTER)	3,341,883
23	FLORENCE MARION 230KV LINE CONSTRUCTION	1,413,420
24	REPLACE RELAY PANELS ON CAMDEN & ROBINSON 115KV LINES	1,485,255
25	TOPD-C LINE RATING ANALYSIS AND RECOVERY (LIDAR)	2,100,395
26	CONTRUCT SANFORD SOUTH 230 KV SUB & TAP	5,068,060
27	BURNSWICK REPLACE INSULATORS	16,213,977
28	FT BRAGG WOODRUFF ST 230KV REPL TRANSFORMER & RECONDUCTOR	7,293,304
29	ROBINSON UNIT 1 SEP-DECOMMISSION	2,277,253
30	OTEEN-WEST ASHEVILLE 115KV LINE-RELOCATE LINE ALONG THOMPSON ST	3,391,643
31	PROJECTS LESS THAN $1 MILLION	27,605,419
32	TOTAL TRANSMISSION PLANT $116,777,354	
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,303,611,534

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	10,689,299,590	10,689,299,590		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	604,487,167	604,487,167		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	7,240,252	7,240,252		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	384,768,476	384,768,476		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	996,495,895	996,495,895		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	620,995,959	620,995,959		
13	Cost of Removal	54,988,754	54,988,754		
14	Salvage (Credit)	83,054,750	83,054,750		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	592,929,963	592,929,963		
16	Other Debit or Cr. Items (Describe, details in footnote):	-4,643,370	-4,643,370		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	11,088,222,152	11,088,222,152		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,036,423,159	2,036,423,159		
21	Nuclear Production	4,495,659,346	4,495,659,346		
22	Hydraulic Production-Conventional	43,464,365	43,464,365		
23	Hydraulic Production-Pumped Storage				
24	Other Production	586,202,197	586,202,197		
25	Transmission	789,438,236	789,438,236		
26	Distribution	2,899,918,382	2,899,918,382		
27	Regional Transmission and Market Operation				
28	General	237,116,467	237,116,467		
29	TOTAL (Enter Total of lines 20 thru 28)	11,088,222,152	11,088,222,152		

Schedule Page: 219 Line No.: 8 Column: c

- ARO Depreciation Expense 108/182	$393,584,279
- Transfer of Reserve for Externally Funded Decontaminated Decommissioning Expense	($11,650,780)
- Wayne and Sutton Depreciation Deferral 403/182	$2,148233
- Amortization of Unrecovered NBV - Weatherspoon 186/403	($1,144,468)
- Transmission Expansion Projects Impairment Amortization 403/107/421	$777,241
- Rotable Fleet Spare Reg Liability Amortization 403/254	$1,053,971
	$384,768,476

Schedule Page: 219 Line No.: 12 Column: c

The difference between the amounts for book cost of plant retired, line 11 of this page, and that reported for electric plant in service, pages 204-207, column (d), is $5,502,043.

This difference is due to book cost of plant retired related to intangible plant in FERC account 303, which has a reserve account of 0111100, Amortization of Other Utility Plant.

Schedule Page: 219 Line No.: 16 Column: c

Coal Ash Cost of Removal Reclass to 182/186	($3,792,856)
Rotable Fleet Spare Transferred Reserve	$305,573
Net Gains on disposal of property	($1,156,087)
	($4,643,370)

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/Q4

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			-7,890
4	Subtotal Capitan Corporation			3,297
5				
6	CaroFund, Inc.	8/15/1995		
7	Common Stock / Equity Contribution			1,678,508
8	Undistributed Earnings			-735,432
9	Subtotal CaroFund, Inc.			943,076
10				
11	CaroHome, LLC	4/21/1995		
12	Common Stock / Equity Contribution			69,674,735
13	Undistributed Earnings			-53,314,629
14	Subtotal CaroHome, LLC			16,360,106
15				
16	Powerhouse Square, LLC	1/16/1998		
17	Common Stock / Equity Contribution			3,054,401
18	Undistributed Earnings			-2,791,993
19	Subtotal Powerhouse Square, LLC			262,408
20				
21	Duke Energy Progress Receivables, LLC	10/16/2013		
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	17,568,887

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
-109		-7,998		3
-109		3,189		4
				5
				6
		1,678,508		7
-12,999		-748,432		8
-12,999		930,076		9
				10
				11
		69,674,735		12
204,800		-52,960,177		13
204,800		16,714,558		14
				15
				16
		3,054,401		17
258,972		-2,533,021		18
258,972		521,380		19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
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				34
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				36
				37
				38
				39
				40
				41
450,664		18,169,203		42

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	04/13/2017	End of 2016/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)	312,175,426	262,286,714	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)	639,907,734	677,587,449	Generation
8	Transmission Plant (Estimated)	50,767,785	31,858,004	Transmission
9	Distribution Plant (Estimated)	49,140,648	71,288,844	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)	739,816,167	780,734,297	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	91,590	163,973	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	36,190,599	32,787,942	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	1,088,273,782	1,075,972,926	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	560,678.00	2,364,295	130,958.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	4,156.00		24,414.00	
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	102,949.00	63,963		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	461,885.00	2,300,332	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				

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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
130,958.00		130,958.00		3,404,908.00		4,358,460.00	2,364,295	1
								2
								3
24,414.00				130,958.00		183,942.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						102,949.00	63,963	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
155,372.00		130,958.00		3,535,866.00		4,439,453.00	2,300,332	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
					38		157	44
					13		55	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 $84,448,864 for renewable energy credits represented in account 0158120

Schedule Page: 228   Line No.: 39   Column: b

Represents allowances withheld in 2016 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	04/13/2017	End of 2016/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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	37,481.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,401.00		16,469.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	NC E Muni Power Agency Ad		242,904		
10					
11					
12					
13					
14					
15	Total		242,904		
16					
17	Relinquished During Year:				
18	Charges to Account 509	14,975.00	242,904		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22		7,495.00			
23					
24					
25					
26					
27					
28	Total	7,495.00			
29	Balance-End of Year	17,412.00		16,469.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		364,389		
34	Gains		364,389		
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				

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.

2018		2019		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						37,481.00		1
								2
								3
16,469.00						35,339.00		4
								5
								6
								7
								8
							242,904	9
								10
								11
								12
								13
								14
							242,904	15
								16
								17
						14,975.00	242,904	18
								19
								20
								21
						7,495.00		22
								23
								24
								25
								26
								27
						7,495.00		28
16,469.00						50,350.00		29
								30
								31
								32
							364,389	33
							364,389	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.

Schedule Page: 229 Line No.: 18 Column: c

The CAIR program expired on 12/31/14. As CAIR inventory previously written-off during 2015 compliance, the NCEMPA overcompliance payment of $242,904 received in 2016 (related to 2015 CAIR compliance) was written-off in 2016 through the 509 account.

Schedule Page: 229 Line No.: 29 Column: b

Ending Balance Includes allowances for the Cross State Air Pollution Rule only

Schedule Page: 229 Line No.: 33 Column: c

Counterparty	Quantity	Cost of Goods Sold	Total Sales Price
Associated Electric Cooperative	5,650	0	$216,500
Ohio Valley Electric	300	0	$90,000
Fathom Energy	1,042	0	$7,294
City of Marshfield Electric & Water	18	0	$4,520
CP Energy Marketing	485	0	$46,075
	7,495	0	$364,389

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	04/13/2017	End of 2016/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 Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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		407	70,766	471,774
22	Robinson Nuclear Plant	13,982,544		407	173,970	2,363,102
23	(7/1987 - 7/2030)					
24	Brunswick Nuclear Plant	35,107,437		407	547,327	10,764,105
25	(1/1987 - 10/2036)					
26						
27	Auth 12/22/2014 begun 1/1/2014					
28	Cape Fear Fsl Ret, Amort 10 yr	11,960,180	1,411,739	407	5,533,894	3,804,080
29	Cape Fear Fsl WS, Amor 10-18 yr	3,829,608	606,441	407	605,328	4,872,281
30	Lee Fossil Retail, Amort 10 yr	16,870,646	2,187,473	407	7,584,286	2,987,191
31	Lee Fossil WS, Amort 23-31 yr	5,401,922	939,673	407	622,504	6,613,616
32	Robinson Fsl Ret, Amort 10 yr	24,861,816	3,710,917	407	4,650,915	30,848,676
33	Robinson Fsl WS, Amort 27 yr	7,960,667	1,594,099	407	417,686	13,498,085
34	Sutton Fsl Ret, Amort 10 yr	28,742,057	4,792,585	407	6,886,285	21,189,747
35	Sutton FS WS, Amort 10-27 yr	9,203,106	2,058,751	407	693,523	11,843,394
36	Weatherspoon Fsl Ret, Amort 10 yr	5,190,969	5,466	407	2,379,397	5,123,274
37	Weatherspoon Fsl WS,Amort 22-28yr	1,662,130	2,348	407	200,634	3,324,776
38	Cape Fear CombTur Ret, Amort 10yr	-231,651		407	-30,272	-140,835
39	Cape Fear CombTur WS, Amort 10 yr	-74,174		407	-11,400	-39,973
40	Lee CombustionTurb Ret,Amort 10yr	1,231,149		407	60,704	1,049,037
41	Lee CombustionTurb WS,Amort 10yr	394,210		407	-30,205	484,824
42	Morehead CombTurb Ret, Amort 10yr	-170,447		407	-17,007	-119,425
43	Morehead CombTurb WS, Amort 10yr	-54,577		407	-12,084	-18,323
44						
45	auth 11/17/2016 begun 12/1/2016					
46	Harris COLA Ret		40,630,005	407		40,630,005
47	Harris COLA WS, Amort 10 yr		7,193,008	407	121,633	7,071,375
48						
49	TOTAL	200,247,557	65,132,505		30,447,884	166,620,786

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	04/13/2017	End of 2016/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	State Studies	(95,000)	0561600		
3	CPLE_PJM East -PTSIS117	108			
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	State Studies	(33,751)	0561700		
23					
24	Summerton Solar - PGFACQ366	127			
25	Asheville Energy CT - PGFACQ368	1,662			
26	Black River Solar - PGFACQ374	92			
27	Sutton CT - PGSISQ334	539			
28	Summerton Solar - PGSISQ366	3,360			
29	Asheville Energy CT - PGSISQ368	6,834			
30	Asheville Energy CT - PGSISQ369	2,570			
31	Blackriver Solar - PGSISQ374	298			
32	Paxville Solar - PGSISQ376	899			
33	Friesian Holdings - PGSISQ380	126			
34	Palmetto Star Solar - PGSISQ385	171			
35	NTE Carolina Solar - PGSISQ386	383			
36	Summerton Solar - PGSISQ394	245			
37	Cumberland 230kV CC -PGSISQ398	61			
38	Cumberland 500kV CC-PGSISQ399	162			
39					
40					

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Fuel Assets (NC Docket E-2, Sub 1031)	92,482,776	72,915,772	various	165,234,748	163,800
2						
3	SFAS 158 Regulatory Assets (NC Docket E-100,	365,991,404	433,340,247	various	376,124,666	423,206,985
4	Sub 913)					
5						
6	Grid South Deferral SC	3,676,168				3,676,168
7						
8	Deferred Fuel Clause: North Carolina Retail	62,660,960	42,273,207	254,557	88,822,344	16,111,823
9	(NC Docket E-2, Sub 1031)					
10						
11	Deferred Fuel Clause: South Carolina Retail	17,714,547	8,305,818	254,557	16,964,088	9,056,277
12	(SC Docket 2013-1-E)					
13						
14	NC REPS Deferral (NC Docket E-2, Sub 1032)	1,900,854	2,471,666	various	4,572,141	-199,621
15						
16	SFAS 143 Regulatory Assets (NC Docket E-2, Sub 826;	210,215,859	127,723,170	various	48,087,535	289,851,494
17	SC Docket 2003-84-E)					
18						
19	SFAS 109 Regulatory Assets	281,436,641	497,322,881	various	478,481,123	300,278,399
20						
21	Accrued Vacation (NC Docket E-2, Sub 859)	38,034,196	2,126,373		2,400,238	37,760,331
22						
23	Gas Pipeline Upgrade	559,349		186,547	54,570	504,779
24	(Amortized over 25 years, ending 2026)					
25						
26	Pollution Control SC (Docket No. 2008-435-E)	32,956,171	2,830,763			35,786,934
27						
28	DSM/EE Deferral NC (NC Docket E-2, Sub 1030)	204,594,667	81,544,959	407,408	57,583,983	228,555,643
29						
30	DSM/EE Deferral SC(Docket No. 2013-76-E)	32,556,903	13,354,519	407,408	11,663,842	34,247,580
31						
32	Wayne County Plant Deferred Costs NC	5,562,064	8,289,740	various	7,513,133	6,338,671
33	(NC Docket E-2, Sub 1026)					
34	(Amortized over 5 years, beginning 2013)					
35						
36	Wayne County Plant Deferred Costs SC	19,557,098	13,737,054	various	12,755,407	20,538,745
37	(SC Docket 2013-155-E)					
38						
39	Rate Case Cost Deferral (NC Docket E-2, Sub 1023)	1,439,375		928	595,603	843,772
40	(Amortized over 5 years, beginning 2013)					
41						
42	Coal Inventory Deferral NC	229,939	105,701	421,456	335,640	
43	(NC Docket E-2, Sub 1023)					
44	TOTAL	2,804,070,065	2,428,320,809		2,133,049,371	3,099,341,503

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	Nuclear Levelization Deferral NC	62,442,248	147,062,738	various	171,179,085	38,325,901
2	(NC Docket E-2, Sub 1023)					
3	(Amortized over 18-24 mths, based on cycle)					
4						
5	Sutton Plant Deferred Costs SC	8,507,895	2,418,823	various		10,926,718
6	(SC Docket 2013-472-E)					
7						
8	Fukushima/Cyber Security Deferral SC	4,259,298	1,246,686	various	1,406,349	4,099,635
9	(SC Docket 2013-472-E)					
10						
11	Coal Ash Basin ARO Deferral NC	1,301,253,772	881,494,366	various	628,246,116	1,554,502,022
12	(NC Coal Ash Management Act of 2014)					
13						
14	Interest rate Swap	5,005,582	5,574,632		5,005,582	5,574,632
15	(NC Docket E-2, Sub 1006; SC Docket 2015-95-E)					
16						
17	Storm Costs Deferral					
18	(SC Docket 2014-482-E)	14,713,413	61		61	14,713,413
19						
20	NCEMPA Purchase Deferral NC	31,056,979	66,689,075	407	54,721,651	43,024,403
21	(NC Docket E-2, Sub 1088)					
22						
23	NCEMPA Purchase Deferral SC	4,985,000	12,904,349	186,407	1,008,349	16,881,000
24	(SC Docket 2015-294-E)					
25						
26	SC DERP Deferral	6,931	573,727	various	23,141	557,517
27	(SC Docket 2015-1-E)					
28						
29	Regulatory Fee DeferralNC	269,976	1,127,493	928	269,976	1,127,493
30	(NC Docket M-100, Sub 142)					
31						
32	Deferred VOP Costs		2,886,989	920		2,886,989
33	(SC Docket 2016-227-E)					
34						
35						
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42						
43						
44	TOTAL	2,804,070,065	2,428,320,809		2,133,049,371	3,099,341,503

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	04/13/2017	End of 2016/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	61,171,492		403/426	49,601,249	11,570,243
2						
3	Interest Rate Hedges	72,525,927	13,241,959	427	26,483,918	59,283,968
4						
5	Accounts in Process of Reclass	113,807	49,873	Various	30,763	132,917
6						
7	Deferred Rate Case Expenses	467,936	521,272	Various	475,515	513,693
8						
9	Gas Pipeline Charges	4,929,790	54,570	547	535,525	4,448,835
10	2001-2026 amortization period					
11						
12	Workers Comp Insurance Reimb	2,385,656	1,450,934	228.2		3,836,590
13						
14	Fukushima Pooled Inventory	1,769,669	36,113	232		1,805,782
15						
16	Cost of Removal Settlement - NC	20,000,000		Various		20,000,000
17						
18	Deferred Coal Ash Remediation	84,088,592	240,571,946	Various	59,306,412	265,354,126
19						
20	NCEMPA SC Equity Reserve	-2,765,000		407	6,636,000	-9,401,000
21						
22	Deferred Storm Costs		985,045,430	421/566	851,917,919	133,127,511
23						
24	Solar Equity Reserve		1,682,555	421	2,432,477	-749,922
25						
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46						
47	Misc. Work in Progress	291,650				453,415
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	244,979,519				490,376,158

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	04/13/2017	End of 2016/Q4

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	1,942,751,307	2,083,860,008
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,942,751,307	2,083,860,008
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)	1,942,751,307	2,083,860,008

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	04/13/2017	End of 2016/Q4

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				
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	04/13/2017	End of 2016/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				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						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	04/13/2017	End of 2016/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

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	04/13/2017	End of 2016/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	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	04/13/2017	End of 2016/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		
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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	48,485,000	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 (1.128% at 12/31/2016)	250,000,000	1,039,782
28			875,000 D
29	Floating Rate Series Due 11/20/2017 (1.111% at 12/31/2016)	200,000,000	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	6,923,485,000	88,903,112

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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			D
7	SUBTOTAL - Account 221	6,473,485,000	86,979,385
8			
9	Account 222 - Reacquired Bonds		
10	None		
11			
12	Account 223 - Advances to Associated Companies:		
13	Commercial Paper Series Due 1/30/2020 (.979% at 12/31/2016)	150,000,000	
14			
15	SUBTOTAL - Account 223	150,000,000	
16			
17	Account 224 - Other Long-Term Debt:		
18	DEP Receivables 300M Due 2/12/2019	300,000,000	1,923,727
19			
20	SUBTOTAL - Account 224	300,000,000	1,923,727
21			
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30			
31			
32			
33	TOTAL	6,923,485,000	88,903,112

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.
						1
						2
02/06/2002	06/01/2041	06/01/2013	06/01/2041	48,485,000	1,939,401	3
						4
01/15/2009	01/15/2019	01/15/2009	01/15/2019	600,000,000	35,364,001	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	18,181,016	9
						10
05/15/2012	05/15/2022	05/15/2012	05/15/2022	500,000,000	18,284,895	11
						12
09/11/2003	09/15/2033	09/11/2003	09/15/2033	200,000,000	12,249,999	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	20,499,999	19
						20
03/12/2013	03/15/2043	03/15/2013	03/15/2043	500,000,000	21,528,999	21
						22
03/06/2014	03/30/2044	03/06/2014	03/30/2044	400,000,000	17,499,999	23
						24
11/20/2014	11/20/2014	11/20/2014	12/01/2044	500,000,000	20,750,001	25
						26
03/06/2014	03/06/2017	03/06/2014	03/06/2017	250,000,000	2,251,567	27
						28
11/20/2014	11/20/2017	11/20/2014	11/20/2017	200,000,000	1,770,425	29
						30
8/13/2015	8/15/2025	8/13/2015	8/15/2025	500,000,000	16,266,667	31
						32
				6,923,485,000	267,592,004	33

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	04/13/2017	End of 2016/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)	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	29,423,334	1
						2
9/16/2016	10/15/2046	9/16/2016	10/15/2046	450,000,000	4,856,250	3
						4
						5
						6
				6,473,485,000	262,549,601	7
						8
						9
						10
						11
						12
12/9/2015	1/30/2020	12/9/2015	1/30/2020	150,000,000	1,322,959	13
						14
				150,000,000	1,322,959	15
						16
						17
12/20/2013	2/12/2019	12/20/2013	2/12/2019	300,000,000	3,719,444	18
						19
				300,000,000	3,719,444	20
						21
						22
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						32
				6,923,485,000	267,592,004	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.

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	04/13/2017	End of 2016/Q4

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)	599,400,762
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	649,447,337
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-50,046,575
28	Show Computation of Tax:	
29		
30	35% of Line 27	-17,516,301
31	Prior Year Federal Tax Adjustments and Audit Settlements	-40,943,257
32		
33	Total Federal Income Tax	-58,459,558
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 20 Column: b

Schedule Page: 261 Line: 20 Column: b

Provision for Deferred Income Taxes	(388,928,334)
Provision for Current Federal Income Taxes	58,459,558
Investment Tax Credit Amortization	5,304,895
COLI Policy Gains/Death Benefits	7,273,294
Asset Retirement Obligations	191,910,934
Book Depreciation/Amortization	(646,743,433)
Tax Depreciation/Amortization	1,435,929,760
Tax Gains/Losses (Cost of Removal)	11,891,377
Equipment/T&D Repairs	154,700,000
AFUDC Equity	49,614,088
AFUDC Interest	16,851,277
Contributions in Aid of Construction	(23,350,616)
Tax Interest Capitalized	(32,828,105)
Nuclear Fuel Book Burned	(196,415,200)
Section 481(a) Casualty Losses	(13,545,381)
Self Developed Software	34,620,947
Non-Cash Overhead Basis Adjustment	(8,833,058)
Unbilled Revenue	3,011,646
Deferred Fuel	(34,398,065)
Benefits Accruals	(23,769,100)
Severance Accrual	13,655,352
Surplus Materials Write-Off	(9,153,516)
Deferred Compensation	1,429,015
Storm Cost Deferral	133,127,511
Charitable Contribution Accruals	(32,345,924)
NC REC Liability	(31,148,453)
End of Life Nuclear Fuel Cost Reserve	(1,785,639)
Lawsuit Contingency	(6,060,303)
Regulatory Asset - Deferred Plant Costs	2,117,547
Regulatory Asset - FAS 158	82,985,351
Regulatory Asset - Nuclear Levelization	(24,116,348)
Regulatory Asset - Save-A-Watt Program	25,651,653
Regulatory Asset - Plant Related Retirements	(12,224,697)
Regulatory Asset - NCEMPA Purchase Deferrals	30,677,230
Net Operating Loss Utilization/Deferral	(126,802,083)
Other Items	2,684,157
Total Differences Between Book & Taxable Income	**649,447,337**

Instruction 2:

The 2016 consolidated tax liability and the allocation thereof have not been finalized. 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	04/13/2017	End of 2016/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	4,102,807		-58,459,558	-251,606,991	-108,257,582
3	Unemployment	4,569		870,633	241,086	-631,098
4	Highway Use			71,366	32,334	-39,032
5	Social Security	4,728,603		41,234,412	40,339,080	1,030,819
6	SUBTOTAL	8,835,979		-16,283,147	-210,994,491	-107,896,893
7						
8	NORTH CAROLINA:					
9	Income	5		-24,346,876	-33,959,646	-7,302,339
10	Property			61,083,763	58,946,028	-1,709,323
11	Franchise			14,051,785	6,265,270	-7,578,297
12	Unemployment	17,090		333,859	337,595	-6,641
13	Municipal License	-152,338		365,611	365,611	
14	Other Taxes			-330,429	-354,602	-24,173
15	SUBTOTAL	-135,243		51,157,713	31,600,256	-16,620,773
16						
17	SOUTH CAROLINA:					
18	Income	55,822		-664,708	-887,881	-283,257
19	Property			33,640,786	34,083,404	442,715
20	Public Utility Corp Licenses	39,818		10,057		
21	Unemployment	1,523		96,682	89,530	-7,058
22	KWH Electric Power			2,169,800	2,169,800	
23	Other Taxes			56,008	-2,333	-58,341
24	Municipal License	6,945,247			9,556,839	9,631,217
25	Privilege License	152,200		1,888,906	2,074,660	-283,081
26	SUBTOTAL	7,194,610		37,197,531	47,084,019	9,442,195
27						
28	GEORGIA:					
29	Unemployment			513	770	
30	SUBTOTAL			513	770	
31						
32	FLORIDA:					
33	Unemployment	-24		1,110	1,086	
34	Other Taxes			-71		71
35	SUBTOTAL	-24		1,039	1,086	71
36						
37	OTHER STATES:					
38	Maryland - FIN 48	296,726				
39	Ohio - FIN 48	1,073,978				
40	Ohio - Unemployment			726	1,080	57
41	TOTAL	17,266,026		72,077,394	-132,306,760	-115,077,958

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	04/13/2017	End of 2016/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Ohio - Other Taxes			-17		17
2	Indiana - Unemployment			1,099	238	-861
3	Louisiana - Unemployment			166	282	
4	California - Franchise			1,809		-1,809
5	Kentucky - Other Taxes			-38		38
6	SUBTOTAL	1,370,704		3,745	1,600	-2,558
7						
8						
9						
10						
11						
12						
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41	TOTAL	17,266,026		72,077,394	-132,306,760	-115,077,958

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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
88,992,658		-53,582,117			-4,877,441	2
3,018		870,633				3
		71,366				4
6,654,754		41,234,412				5
95,650,430		-11,405,706			-4,877,441	6
						7
						8
2,310,436		-23,187,419			-1,159,457	9
428,412		59,353,511			1,730,252	10
208,218		14,051,785				11
6,713		333,859				12
-152,338		365,611				13
		-330,429				14
2,801,441		50,586,918			570,795	15
						16
						17
-4,262		-659,700			-5,008	18
97		33,580,761			60,025	19
49,875		10,057				20
1,617		96,682				21
		2,169,800				22
		56,008				23
7,019,625						24
-316,635		1,888,906				25
6,750,317		37,142,514			55,017	26
						27
						28
-257		513				29
-257		513				30
						31
						32
		1,110				33
		-71				34
		1,039				35
						36
						37
296,726						38
1,073,978						39
-297		726				40
106,572,222		76,329,023			-4,251,629	41

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 (I) 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)	
		-17				1
		1,099				2
-116		166				3
		1,809				4
		-38				5
1,370,291		3,745				6
						7
						8
						9
						10
						11
						12
						13
						14
						15
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						37
						38
						39
						40
106,572,222		76,329,023			-4,251,629	41

Schedule Page: 262 Line No.: 2 Column: f

Reclass taxes charged/paid to/from account 146	(100,898,320)
Reclass FIN 48 balance to/from account 143	(7,359,262)
	(108,257,582)

Schedule Page: 262 Line No.: 3 Column: f

Current year taxes charged offset to account 107	137,267
Current year taxes charged offset to account 242	(808,004)
Current year taxes charged offset to account 254	39,639
	(631,098)

Schedule Page: 262 Line No.: 4 Column: f

Current year taxes charged offset to account 146	(39,032)
	(39,032)

Schedule Page: 262 Line No.: 5 Column: f

Current year taxes charged offset to account 146	(616,488)
Current year taxes charged offset to account 254	517
Current year taxes charged offset to account 242	1,647,101
Current year taxes charged offset to account 241	(311)
	1,030,819

Schedule Page: 262 Line No.: 9 Column: f

Reclass taxes charged/paid to/from account 146	(5,509,729)
Reclass account 236 with non-FERC business unit	(306,014)
Reclass FIN 48 balance to/from account 143	(1,486,596)
	(7,302,339)

Schedule Page: 262 Line No.: 10 Column: f

Current year taxes charged offset to account 232	(22,635)
Current year taxes charged offset to account 182	(61,007)
Current year taxes charged offset to account 146	(1,618,304)
CAPS Accrual Entry	(7,377)
	(1,709,323)

Schedule Page: 262 Line No.: 11 Column: f

Current year taxes charged offset to account 143	(1,289,568)
Current year taxes charged offset to account 146	(6,288,729)
	(7,578,297)

Schedule Page: 262 Line No.: 12 Column: f

Current year taxes charged offset to account 146	(58)
Current year taxes charged offset to account 241	(6,583)
	(6,641)

Schedule Page: 262 Line No.: 14 Column: f

Current year taxes charged offset to account 146	(24,173)
	(24,173)

Schedule Page: 262 Line No.: 18 Column: f

Reclass taxes charged/paid to/from account 146	(77,333)
Reclass account 236 with non-FERC business unit	(45,556)
Reclass FIN 48 balance to/from account 143	(160,368)
	(283,257)

Schedule Page: 262 Line No.: 19 Column: f

Current year taxes charged offset to account 182	442,715
	442,715

Schedule Page: 262 Line No.: 21 Column: f

Current year taxes charged offset to account 241	(7,058)
	(7,058)

Schedule Page: 262 Line No.: 23 Column: f

Account 236 offset to account 142	(58,341)
	(58,341)

Schedule Page: 262 Line No.: 24 Column: f

Account 236 offset to account 142	9,631,217
	9,631,217

Schedule Page: 262 Line No.: 25 Column: f

Current year taxes charged offset to account 146	(283,081)
	(283,081)

Schedule Page: 262 Line No.: 34 Column: f

Current year taxes charged offset to account 146	71
	71

Schedule Page: 262 Line No.: 40 Column: f

Current year taxes charged offset to account 241	57
	57

Schedule Page: 262.1 Line No.: 1 Column: f

Current year taxes charged offset to account 146	17
	17

Schedule Page: 262.1 Line No.: 2 Column: f

Current year taxes charged offset to account 241	(861)
	(861)

Schedule Page: 262.1 Line No.: 4 Column: f

Current year taxes charged offset to account 146	(1,809)
	(1,809)

Schedule Page: 262.1 Line No.: 5 Column: f

Current year taxes charged offset to account 146	38
	38

Schedule Page: 262.1 Line No.: 7 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 – 864,891 Excluded from Balance At Beginning Of Year (column b)
Sales and Use Tax Payable – 1,254,199 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	04/13/2017	End of 2016/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%	4,033,223			411.4	590,597	
4	7%						
5	10%	60,671,151			411.4	4,143,135	
6	6%	138,468			411.4	4,369	
7		66,761,517		23,352,299		566,794	-3,252,115
8	TOTAL	131,604,359		23,352,299		5,304,895	-3,252,115
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	8%	6,734,628			411.4	566,794	
11	30%	60,026,889	255	23,352,299			-3,252,115
12	TOTAL	66,761,517		23,352,299		566,794	-3,252,115
13							
14							
15							
16							
17							
18							
19							
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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	04/13/2017	End of 2016/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
3,442,626	37-58 Years		3
			4
56,528,016	37-58 Years		5
134,099	37-58 Years		6
86,294,907	37-58 Years		7
146,399,648			8
			9
6,167,834	37-58 Years		10
80,127,073			11
86,294,907			12
			13
			14
			15
			16
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			18
			19
			20
			21
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			48

Schedule Page: 266 Line No.: 7 Column: g

The deferral of $59,468,160 reported for 2015 represented an estimate of the 30% investment tax credits for the Fayetteville, Warsaw and Jacksonville Solar Projects. During 2016, the 2015 Federal Tax Return was filed and the actual amount of the credits was lower than originally estimated. This adjustment represents the reduction to the estimated amount.

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	04/13/2017	End of 2016/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	2,304,384	143.6	770,258		1,534,126
2						
3	NC Eastern Municipal Power					
4	Agency	98,569	Various	98,596	27	
5						
6	CATV Pole Rent	3,886,365	Various	3,555,477	3,624,783	3,955,671
7						
8	Environmental Reserve for					
9	Manufactured Gas Plants	606,550	426.5	977,907	784,002	412,645
10						
11	NC Tax Rate Change	29,923,868	Various	58,652,264	53,465,956	24,737,560
12						
13						
14	Tariff Admin	195,000	None			195,000
15						
16	Cash Collections	4,619,869	Various	1,454,816	99,267	3,264,320
17						
18	Piedmont Natural Gas Merger					
19	Donation Commitment		426.1		22,125,000	22,125,000
20						
21	Minor Items	17,215	Various	29,963	92,019	79,271
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	41,651,820		65,539,281	80,191,054	56,303,593

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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 (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	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	04/13/2017	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							10
							11
							12
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							15
							16
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							18
							19
							20
							21

NOTES (Continued)

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	3,739,969,531	698,923,694	481,458,378
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,739,969,531	698,923,694	481,458,378
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	3,739,969,531	698,923,694	481,458,378
10	Classification of TOTAL			
11	Federal Income Tax	3,382,470,594	655,934,007	448,862,941
12	State Income Tax	357,498,937	42,989,687	32,595,437
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
7,595,910	-223,510	254	77,017,068	182/253	14,643,501	3,902,880,700	2
							3
							4
7,595,910	-223,510		77,017,068		14,643,501	3,902,880,700	5
							6
							7
							8
7,595,910	-223,510		77,017,068		14,643,501	3,902,880,700	9
							10
7,384,837	232,635		4,569,372		15,364,391	3,607,488,881	11
211,073	-456,145		72,447,696		-720,890	295,391,819	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: g

254 - North Carolina Rate Change	$45,329,081
254 - Other Regulatory Liabilities	31,687,987
Total	$77,017,068

Schedule Page: 274 Line No.: 2 Column: i

182 - Regulatory Assets	$13,410,034
253 - North Carolina Rate Change	1,233,467
Total	$14,643,501

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	04/13/2017	End of 2016/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	1,230,272,857	380,524,141	98,845,154
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,230,272,857	380,524,141	98,845,154
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)	1,230,272,857	380,524,141	98,845,154
20	Classification of TOTAL			
21	Federal Income Tax	1,098,925,287	359,683,950	100,833,547
22	State Income Tax	131,347,570	20,840,191	-1,988,393
23	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	04/13/2017	End of 2016/Q4

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
3,098,035	321,967		15,861,486	182	5,431,725	1,504,298,151	3
							4
							5
							6
							7
							8
3,098,035	321,967		15,861,486		5,431,725	1,504,298,151	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
3,098,035	321,967		15,861,486		5,431,725	1,504,298,151	19
							20
2,806,378	287,012		-8,146,311		7,216,452	1,375,657,819	21
291,657	34,955		24,007,797		-1,784,727	128,640,332	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: g

146 - Intercompany Transactions	$ 264,094
253 - North Carolina Rate Change	1,965,564
254 - North Carolina Rate Change	13,631,828
Total	$15,861,486

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	EPA Emission Allowances (NC Docket E-2, Sub 1023)	6,177,644	407	2,499,899		3,677,745
2	Amortized over 5 yrs beginning June, 2013.					
3						
4	SFAS 109 Regulatory Liabilities	85,308,008	various	178,002,744	235,382,256	142,687,520
5						
6	Deferred Fuel Clause: North Carolina Retail	51,301,063	182	11,028,257	69,695,461	109,968,267
7	(NC Docket E-2, Sub 1031)					
8						
9	Deferred Fuel Clause: South Carolina Retail	6,998,693	182	53,330,902	212,272	-46,119,937
10	(SC Docket 2013-1-E)					
11						
12	DOE Refund Deferral (NC Docket E-2, Sub 1023)	6,797,537	various	2,549,076		4,248,461
13	Amortized over 7 yrs ending 2018.					
14						
15	SFAS 143 Regulatory Liabilities (NC Docket E-2,	15,264,104				15,264,104
16	Sub 826; SC Docket 2003-84-E)					
17						
18	Nuclear Decommissioning Trust - Unrealized Gains	579,810,649	128,182	128,116,635	229,403,731	681,097,745
19	(NC Docket E-2, Sub 826; SC Docket 2003-84-E)					
20						
21	NC REPS Deferral (NC Docket E-2 Sub 1032)	77,954,347	various	19,918,028	28,592,625	86,628,944
22						
23	Nuclear Fuel Last Core Reserve	20,847,719			8,070,085	28,917,804
24	(NC Docket E-2, Sub 1023)					
25						
26	Harris Land Sale Gains	3,720,318	407	1,539,442		2,180,876
27	(NC Docket E-2, Sub 1023)					
28	Amortized over 5 yrs beginning June 2013.					
29						
30	NC Tax Rate Change	89,997,750		190,562,490	251,030,365	150,465,625
31	(NC Docket E-2, Sub 1046)					
32						
33	OPEB Reg Liability	25,025,461	various	50,360,970	25,418,610	83,101
34						
35	NCDT Overfund Liability	6,284,446		8,997,795	2,713,349	
36	(SC Docket 2013-472 E)					
37						
38	Open Interest rate Swap	841,823	various	40,978,195	87,056,049	46,919,677
39	(NC Docket E-2, Sub 1006; SC Docket 2015-95-E)					
40						
41	TOTAL	978,680,077		688,938,404	939,145,445	1,228,887,118

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	04/13/2017	End of 2016/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	2,350,515	various	1,053,971	1,570,642	2,867,186
2	(NC Docket E-2, Sub 998A)					
3						
4						
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33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	978,680,077		688,938,404	939,145,445	1,228,887,118

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	04/13/2017	End of 2016/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	1,917,409,351	1,927,926,797
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,240,031,513	1,246,882,218
5	Large (or Ind.) (See Instr. 4)	637,611,854	664,461,572
6	(444) Public Street and Highway Lighting	20,345,197	21,930,592
7	(445) Other Sales to Public Authorities	84,996,646	92,754,066
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,900,394,561	3,953,955,245
11	(447) Sales for Resale	1,234,198,215	1,160,505,311
12	TOTAL Sales of Electricity	5,134,592,776	5,114,460,556
13	(Less) (449.1) Provision for Rate Refunds	-699,832	-1,699,993
14	TOTAL Revenues Net of Prov. for Refunds	5,135,292,608	5,116,160,549
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,752,736	9,996,678
17	(451) Miscellaneous Service Revenues	7,790,254	8,385,245
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	37,054,303	37,751,018
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	10,316,292	24,704,079
22	(456.1) Revenues from Transmission of Electricity of Others	67,549,828	69,195,348
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	130,463,413	150,032,368
27	TOTAL Electric Operating Revenues	5,265,756,021	5,266,192,917

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
17,946,817	17,685,926	1,291,742	1,274,550	2
				3
14,094,399	14,019,694	229,002	226,094	4
10,266,479	10,274,406	4,136	4,209	5
87,536	105,945	1,537	1,677	6
1,472,596	1,489,013	5	5	7
				8
				9
43,867,827	43,574,984	1,526,422	1,506,535	10
25,184,327	21,305,576	15	16	11
69,052,154	64,880,560	1,526,437	1,506,551	12
				13
69,052,154	64,880,560	1,526,437	1,506,551	14

Line 12, column (b) includes $ 21,599,287 of unbilled revenues.

Line 12, column (d) includes 262,080 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

Includes $6,096,168 of service charges and $1,694,086 of miscellaneous service revenue.

Schedule Page: 300 Line No.: 17 Column: c

Includes $6,124,232 of service charges and $2,261,013 of miscellaneous service revenue.

Schedule Page: 300 Line No.: 21 Column: b

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).

Schedule Page: 300 Line No.: 21 Column: c

Includes $19,861,678 of coal blended savings as a result of the merger with Duke Energy, $3,415,858 of contributions in aid of construction revenue, $391,508 of compensation for service to others revenue,$410,793 of electric revenue from cogeneration/small power producers and coal inventory rider credits $(266,096).

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	04/13/2017	End of 2016/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					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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38					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	Residential					
2	RES	17,586,694	1,853,574,952	1,288,226	13,652	0.1054
3	SLR	17,126	6,331,444	3,516	4,871	0.3697
4	ALS	82,425	21,166,501			0.2568
5	Unbilled	260,571	19,823,165			0.0761
6	TOTAL RESIDENTIAL	17,946,816	1,900,896,062	1,291,742	13,893	0.1059
7						
8	Commercial					
9	ALS	259,766	54,078,497			0.2082
10	APH-TES	2,151	136,086	3	717,000	0.0633
11	CH-TOUE	8,107	1,160,654	227	35,714	0.1432
12	CS	2,641	376,209	91	29,022	0.1424
13	LGS	1,257,348	90,437,166	98	12,830,082	0.0719
14	MGS	2,760,381	264,797,316	18,279	151,014	0.0959
15	SFLS	1,326	244,296	95	13,958	0.1842
16	SGS	9,709,682	799,738,617	207,688	46,751	0.0824
17	SI	64,992	7,102,333	1,172	55,454	0.1093
18	SLS	12,295	4,058,393	1,111	11,067	0.3301
19	TFS	179	34,369	108	1,657	0.1920
20	TSS	275	24,702	39	7,051	0.0898
21	GS	3,355	408,648	91	36,868	0.1218
22	Unbilled Revenue	11,901	1,898,719			0.1595
23	TOTAL COMMERCIAL	14,094,399	1,224,496,005	229,002	61,547	0.0869
24						
25	Industrial					
26	ALS	20,272	3,464,083			0.1709
27	LGS	7,796,403	445,440,981	254	30,694,500	0.0571
28	MGS	524,145	50,180,877	1,256	417,313	0.0957
29	SGS	1,930,678	136,852,222	2,581	748,035	0.0709
30	SI	2,241	226,402	21	106,714	0.1010
31	SLS	127	23,689	20	6,350	0.1865
32	GS	199	32,988	4	49,750	0.1658
33	Unbilled Revenue	-7,586	-104,574			0.0138
34	TOTAL INDUSTRIAL	10,266,479	636,116,668	4,136	2,482,224	0.0620
35						
36	Public Street Lighting					
37	SLS	82,580	19,798,368	592	139,493	0.2397
38	TSS	6,046	529,410	945	6,398	0.0876
39	Unbilled Revenue	-1,090	-60,063			0.0551
40	TOTAL PUBLIC STREET LIGHT	87,536	20,267,715	1,537	56,953	0.2315
41	TOTAL Billed	43,605,747	3,878,795,275	1,526,421	28,567	0.0890
42	Total Unbilled Rev.(See Instr. 6)	262,080	21,599,287	0	0	0.0824
43	TOTAL	43,867,827	3,900,394,562	1,526,421	28,739	0.0889

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	04/13/2017	End of 2016/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	232			0.1160
4	MGS					
5	LGS	1,474,309	84,951,370	5	294,861,800	0.0576
6	Unbilled Revenue	-1,715	42,040			-0.0245
7	TOTAL OTHER PUBLIC AUTH	1,472,596	84,993,642	5	294,519,200	0.0577
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						
41	TOTAL Billed	43,605,747	3,878,795,275	1,526,421	28,567	0.0890
42	Total Unbilled Rev.(See Instr. 6)	262,080	21,599,287	0	0	0.0824
43	TOTAL	43,867,827	3,900,394,562	1,526,421	28,739	0.0889

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 and DERP revenues. REPS and DERP revenue are not allocated by rate code. The REPS revenue excluded from this line is $16,274,646 and the DERP revenue excluded is $238,643.

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 and DERP revenues. REPS and DERP revenue are not allocated by rate code. The REPS revenue excluded from this line is $15,418,922 and the DERP revenue excluded is $116,586.

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 and DERP revenues. REPS and DERP revenue are not allocated by rate code. The REPS revenue excluded from this line is $1,458,571 and the DERP revenue excluded is $36,616.

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 and DERP revenues. REPS and DERP revenue are not allocated by rate code. The REPS revenue excluded from this line is $76,853 and the DERP revenue excluded is $630.

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 and DERP revenues. REPS and DERP revenue are not allocated by rate code. The REPS revenue excluded from this line is $2,864 and the DERP revenue excluded is $140.

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Requirement Sales					
2						
3	Town of Black Creek, NC	RQ	174	3	3	3
4	Town of Black Creek, NC	RQ	174			
5	City of Camden, SC	RQ	197	37	38	37
6	City of Camden, SC	RQ	197			
7	PWC of the City of Fayetteville	RQ	184	361	372	361
8	PWC of the City of Fayetteville	RQ	184			
9	French Broad EMC	RQ	195	80	85	80
10	French Broad EMC	RQ	195			
11	Haywood EMC	RQ	180	11	21	16
12	Haywood EMC	RQ	180			
13	Town of Lucama, NC	RQ	175	4	4	4
14	Town of Lucama, NC	RQ	175			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	NC Electric Membership Corporation	RQ	134	970	970	970
2	NC Electric Membership Corporation	RQ	134			
3	NC Electric Membership Corporation	RQ	182	651	671	651
4	NC Electric Membership Corporation	RQ	182			
5	NC Eastern Municipal Power Agency	RQ	200	1029	1246	1029
6	NC Eastern Municipal Power Agency	RQ	200			
7	Piedmont EMC	RQ	172	18	19	18
8	Piedmont EMC	RQ	172			
9	Town of Sharpsburg, NC	RQ	176	4	4	4
10	Town of Sharpsburg, NC	RQ	176			
11	Town of Stantonsburg, NC	RQ	177	4	4	4
12	Town of Stantonsburg, NC	RQ	177			
13	Town of Waynesville, NC	RQ	185	12	13	12
14	Town of Waynesville, NC	RQ	185			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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 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	Town of Winterville, NC	RQ	178	11	11	11
2	Town of Winterville, NC	RQ	178			
3						
4	Non-Requirement Sales					
5						
6	PJM Interconnection L.L.C	OS	7			
7	PJM Interconnection L.L.C	AD	7			
8	South Carolina Electric & Gas Company	OS	97			
9	South Carolina Public Service Authority	OS	104			
10	Duke Energy Carolinas, LLC	LF	190			
11	Duke Energy Carolinas, LLC	AD	190			
12	NC Electric Membership Corporation	OS	4			
13	NC Electric Membership Corporation	AD	4			
14	NC Electric Membership Corporation	OS	134			
	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	04/13/2017	End of 2016/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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	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	NC Eastern Municipal Power Agency	OS	268			
2	Piedmont EMC	OS	322			
3	Haywood EMC	OS	300			
4	Town of Black Creek, NC	OS	293			
5	City of Camden, SC	OS	309			
6	PWC of the City of Fayetteville	OS	324			
7	French Broad EMC	OS	326			
8	Town of Lucama, NC	OS	294			
9	Town of Sharpsburg, NC	OS	296			
10	Town Stantonsburg	OS	295			
11	Town of Waynesville, NC	OS	303			
12	Town of Winterville, NC	OS	321			
13	Industrial Power Generating Corp.	OS	288			
14	Cargill-Alliant, LLC	OS				
	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	04/13/2017	End of 2016/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:
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	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	North Carolina Municipal PA1	OS				
2	Other	AD				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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	04/13/2017	End of 2016/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.
					1
					2
13,210	462,708	388,656		851,364	3
		-4,768		-4,768	4
201,806	6,885,186	5,287,965		12,173,151	5
	12,600	-64,762		-52,162	6
2,164,366	71,453,722	56,804,899		128,258,621	7
	2,174,079	-191,682		1,982,397	8
530,998	15,305,120	13,859,568		29,164,688	9
	74,750	-446,779		-372,029	10
79,347	1,968,252	2,073,982		4,042,234	11
	558	-35,917		-35,359	12
20,521	719,089	603,922		1,323,011	13
		-7,141		-7,141	14
18,561,883	580,020,088	482,115,685	0	1,062,135,773	
6,622,444	7,830,000	164,136,333	96,109	172,062,442	
25,184,327	**587,850,088**	**646,252,018**	**96,109**	**1,234,198,215**	

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.
6,700,064	136,048,487	175,066,690		311,115,177	1
223		62,649		62,649	2
936,991	129,267,821	24,796,403		154,064,224	3
	-133,171	-3,878,182		-4,011,353	4
7,650,655	203,957,221	200,030,053		403,987,274	5
	3,475,504	679,087		4,154,591	6
70,530	3,293,521	1,835,649		5,129,170	7
	7,398	-20,508		-13,110	8
19,850	670,619	585,697		1,256,316	9
		-7,184		-7,184	10
23,170	761,598	683,970		1,445,568	11
		-7,519		-7,519	12
95,976	2,062,732	2,502,030		4,564,762	13
	3,347	-73,295		-69,948	14
18,561,883	580,020,088	482,115,685	0	1,062,135,773	
6,622,444	7,830,000	164,136,333	96,109	172,062,442	
25,184,327	**587,850,088**	**646,252,018**	**96,109**	**1,234,198,215**	

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.
54,176	1,548,947	1,611,217		3,160,164	1
		-19,015		-19,015	2
					3
					4
					5
95,937		4,050,611		4,050,611	6
		-8,110		-8,110	7
741		43,615		43,615	8
265		11,284		11,284	9
6,408,111		156,459,542		156,459,542	10
71		-51,719		-51,719	11
114,401	7,830,000	3,630,841		11,460,841	12
		269		269	13
2,340			90,329	90,329	14
18,561,883	580,020,088	482,115,685	0	1,062,135,773	
6,622,444	7,830,000	164,136,333	96,109	172,062,442	
25,184,327	**587,850,088**	**646,252,018**	**96,109**	**1,234,198,215**	

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.
			-2,105	-2,105	1
			-40	-40	2
			-41	-41	3
			-5	-5	4
			-74	-74	5
			-676	-676	6
			-127	-127	7
			-8	-8	8
			-7	-7	9
			-9	-9	10
			-21	-21	11
			-20	-20	12
586			9,204	9,204	13
			-29	-29	14
18,561,883	580,020,088	482,115,685	0	1,062,135,773	
6,622,444	7,830,000	164,136,333	96,109	172,062,442	
25,184,327	**587,850,088**	**646,252,018**	**96,109**	**1,234,198,215**	

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	04/13/2017	End of 2016/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.
			-262	-262	1
-8					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
18,561,883	580,020,088	482,115,685	0	1,062,135,773	
6,622,444	7,830,000	164,136,333	96,109	172,062,442	
25,184,327	**587,850,088**	**646,252,018**	**96,109**	**1,234,198,215**	

Schedule Page: 310 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 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 Line No.: 8 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.: 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 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 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: 310.1 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: 310.1 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: 310.1 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: 310.1 Line No.: 8 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.: 10 Column: a

Duke Energy Carolinas, LLC is an affiliate of Duke Energy Progress.

Schedule Page: 310.2 Line No.: 11 Column: a

Duke Energy Carolinas, LLC is an affiliate of Duke Energy Progress.

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	04/13/2017	End of 2016/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	8,823,917	11,148,495
5	(501) Fuel	410,031,826	479,906,263
6	(502) Steam Expenses	23,111,112	30,684,964
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		-3,478
9	(505) Electric Expenses	84,862	744,519
10	(506) Miscellaneous Steam Power Expenses	7,145,638	21,136,946
11	(507) Rents		
12	(509) Allowances	306,867	604,367
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	449,504,222	544,229,032
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,844,048	12,404,049
16	(511) Maintenance of Structures	9,413,704	16,793,596
17	(512) Maintenance of Boiler Plant	43,515,606	44,780,502
18	(513) Maintenance of Electric Plant	9,787,139	16,556,954
19	(514) Maintenance of Miscellaneous Steam Plant	6,152,852	11,290,458
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	75,713,349	101,825,559
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	525,217,571	646,054,591
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	44,785,075	39,957,242
25	(518) Fuel	199,311,766	173,309,480
26	(519) Coolants and Water	20,399,547	20,188,412
27	(520) Steam Expenses	50,372,305	49,721,067
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	6,133,709	4,504,006
31	(524) Miscellaneous Nuclear Power Expenses	170,974,243	179,702,112
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	491,976,645	467,382,319
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	72,169,715	79,389,689
36	(529) Maintenance of Structures	25,715,675	22,903,584
37	(530) Maintenance of Reactor Plant Equipment	67,425,121	96,858,438
38	(531) Maintenance of Electric Plant	48,809,983	46,574,844
39	(532) Maintenance of Miscellaneous Nuclear Plant	61,211,282	69,976,296
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	275,331,776	315,702,851
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	767,308,421	783,085,170
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,812,177	1,659,500
45	(536) Water for Power	62,500	62,500
46	(537) Hydraulic Expenses	-223,725	-310,873
47	(538) Electric Expenses	91,095	540,179
48	(539) Miscellaneous Hydraulic Power Generation Expenses	789,899	1,156,120
49	(540) Rents		667
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,531,946	3,108,093
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	218,008	350,216
54	(542) Maintenance of Structures	331,428	232,968
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,439,806	1,190,676
56	(544) Maintenance of Electric Plant	456,821	497,265
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,234,903	1,269,021
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,680,966	3,540,146
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	7,212,912	6,648,239

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	04/13/2017	End of 2016/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	4,459,099	5,993,988
63	(547) Fuel	679,990,220	866,968,251
64	(548) Generation Expenses	3,098,072	4,159,548
65	(549) Miscellaneous Other Power Generation Expenses	13,150,559	15,031,798
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	700,697,950	892,153,585
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	4,283,381	4,752,939
70	(552) Maintenance of Structures	7,770,653	4,282,513
71	(553) Maintenance of Generating and Electric Plant	30,672,705	9,897,418
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	15,454,100	11,729,341
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	58,180,839	30,662,211
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	758,878,789	922,815,796
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	485,581,581	430,562,658
77	(556) System Control and Load Dispatching	1,629,675	1,411,430
78	(557) Other Expenses	145,624,149	170,193,106
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	632,835,405	602,167,194
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,691,453,098	2,960,770,990
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	-4,530	48,555
84			
85	(561.1) Load Dispatch-Reliability	2,436,540	2,913,179
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,191,336	1,809,906
87	(561.3) Load Dispatch-Transmission Service and Scheduling	940,162	830,944
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	292,406	267
90	(561.6) Transmission Service Studies	-94,892	2,499
91	(561.7) Generation Interconnection Studies	-16,221	99,546
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,465,991	2,154,976
94	(563) Overhead Lines Expenses	844,247	1,159,007
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	761	10,310
97	(566) Miscellaneous Transmission Expenses	6,916,068	6,239,548
98	(567) Rents	95,951	1,663,464
99	TOTAL Operation (Enter Total of lines 83 thru 98)	15,067,819	16,932,201
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	3,502	3,795
102	(569) Maintenance of Structures	280,089	807,975
103	(569.1) Maintenance of Computer Hardware	27,684	4,845
104	(569.2) Maintenance of Computer Software	2,735,383	2,162,739
105	(569.3) Maintenance of Communication Equipment	10,142	28,649
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,599,790	4,742,109
108	(571) Maintenance of Overhead Lines	23,519,116	13,679,133
109	(572) Maintenance of Underground Lines	-1,192	272,726
110	(573) Maintenance of Miscellaneous Transmission Plant	-759,297	84,612
111	TOTAL Maintenance (Total of lines 101 thru 110)	31,415,217	21,786,583
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	46,483,036	38,718,784

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	04/13/2017	End of 2016/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)
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	717,977	1,296,078
135	(581) Load Dispatching	5,214,815	6,006,770
136	(582) Station Expenses	1,341,524	1,519,184
137	(583) Overhead Line Expenses	191,075	745,573
138	(584) Underground Line Expenses	4,712,175	4,081,995
139	(585) Street Lighting and Signal System Expenses	10,276	11,103
140	(586) Meter Expenses	7,511,340	3,821,334
141	(587) Customer Installations Expenses	2,013,972	1,639,608
142	(588) Miscellaneous Expenses	25,567,942	22,929,206
143	(589) Rents	2,533,934	2,669,866
144	TOTAL Operation (Enter Total of lines 134 thru 143)	49,815,030	44,720,717
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	8,189	13,916
147	(591) Maintenance of Structures	1,296	15,336
148	(592) Maintenance of Station Equipment	4,077,049	4,832,818
149	(593) Maintenance of Overhead Lines	96,344,656	70,815,301
150	(594) Maintenance of Underground Lines	4,822,769	5,153,125
151	(595) Maintenance of Line Transformers	798,661	908,083
152	(596) Maintenance of Street Lighting and Signal Systems	6,812,010	6,979,238
153	(597) Maintenance of Meters	1,801,325	1,717,984
154	(598) Maintenance of Miscellaneous Distribution Plant	1,426,022	3,479,012
155	TOTAL Maintenance (Total of lines 146 thru 154)	116,091,977	93,914,813
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	165,907,007	138,635,530
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	281,077	202,113
160	(902) Meter Reading Expenses	4,468,044	3,944,389
161	(903) Customer Records and Collection Expenses	35,514,951	35,535,783
162	(904) Uncollectible Accounts	6,972,450	12,517,092
163	(905) Miscellaneous Customer Accounts Expenses	663,023	730,728
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	47,899,545	52,930,105

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	04/13/2017	End of 2016/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	5,832	2,460
169	(909) Informational and Instructional Expenses	81,137	36,122
170	(910) Miscellaneous Customer Service and Informational Expenses	4,393,350	3,669,053
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	4,480,319	3,707,635
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	5,976,581	5,298,702
176	(913) Advertising Expenses	314,113	190,167
177	(916) Miscellaneous Sales Expenses	16,591	135,150
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	6,307,285	5,624,019
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	116,700,862	100,816,653
182	(921) Office Supplies and Expenses	43,547,509	47,800,250
183	(Less) (922) Administrative Expenses Transferred-Credit	-78,844	-116,243
184	(923) Outside Services Employed	46,129,197	61,478,095
185	(924) Property Insurance	18,253,708	18,283,752
186	(925) Injuries and Damages	16,348,146	18,324,398
187	(926) Employee Pensions and Benefits	87,327,116	49,136,821
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,495,556	8,057,238
190	(929) (Less) Duplicate Charges-Cr.	3,209,674	16,739,550
191	(930.1) General Advertising Expenses	2,196,396	2,742,401
192	(930.2) Miscellaneous General Expenses	-29,538,333	-16,812,480
193	(931) Rents	33,939,086	26,771,528
194	TOTAL Operation (Enter Total of lines 181 thru 193)	339,268,413	299,975,349
195	Maintenance		
196	(935) Maintenance of General Plant	1,397,538	-459,102
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	340,665,951	299,516,247
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,303,196,241	3,499,903,310

Schedule Page: 320 Line No.: 5 Column: b

Amount reflects $3,294,460 of merger related fuel synergies not allocated by plant.

Schedule Page: 320 Line No.: 6 Column: b

Amount reflects ($148,685) of merger related reagent and by-product synergies not allocated to plant.

Schedule Page: 320 Line No.: 63 Column: b

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	04/13/2017	End of 2016/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.

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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	1529 Properties, LLC	LU	1			
2	2315 Atlantic Ave Solar LLC	LU	1			
3	ABCZ Solar LLC	LU	1			
4	Adnan Nasir	LU	1			
5	Adventure Solar	LU	1			
6	Alan Hardacre	LU	1			
7	Albert Adcock	LU	1			
8	Albertson Solar LLC	LU	1			
9	Alice Martin-Adkins	LU	1			
10	Alice Rosser	LU	1			
11	Alina Szmant	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	04/13/2017	End of 2016/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	Ambient Advisory Services INC	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 LLC	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 4 LLC	LU	1			
13	Argand SPP2 LLC	LU	1			
14	Arthur Zuco	LU	1			
	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	Aspen Solar LLC	LU	1			
2	Atkinson Farm, LLC	LU	1			
3	Axiom Environmental INC	LU	1			
4	B & K Timber LLC	LU	1			
5	B.V. Hedrick Gravel & Sand Co	LU	1			
6	B2R2 LLC (The Southern Landscape)	LU	1			
7	Balsam Solar, LLC	LU	1			
8	Barkley-Sexton Energy LLC	LU	1			
9	Barry Estes	LU	1			
10	Battye Solar LLC	LU	1			
11	Bayer Cropscience LP	LU	1			
12	Beaufort Solar	LU	1			
13	Ben Edson	LU	1			
14	Bertram Kalet	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	04/13/2017	End of 2016/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	Beulaville Solar LLC	LU	1			
2	Beverly Lincoln	LU	1			
3	BGE Carolina Sunsense I LLC	LU	1			
4	Billy Moon	LU	1			
5	Biltmore Natural Resources INC	LU	1			
6	Biscoe Solar	LU	1			
7	Bizzell Church Solar	LU	1			
8	Black Creek	LU	1			
9	Bladenboro Farm, LLC	LU	1			
10	Bladenboro Solar, LLC	LU	1			
11	Blueberry One	LU	1			
12	Bolton Farm, LLC	LU	1			
13	Boone Guyton	LU	1			
14	BRE NC Solar 1 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	04/13/2017	End of 2016/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	Brenda Currin	LU	1			
2	Brian Gualano	LU	1			
3	Broadway Solar	LU	1			
4	Brooks Energy	LU	1			
5	Bruce Ford	LU	1			
6	Buncombe County Landfill	LU	1			
7	C II METHANE MANAGEMENT IV LLC	LU	1			
8	Camilla Vance-Holmes	LU	1			
9	Camp Rockmont for Boys INC	LU	1			
10	Candace Solar	LU	1			
11	Carolina Solar Energy, NCSU	LU	1			
12	Carolina Solar Energy, PCSP1	LU	1			
13	Carolina Solar Energy-EMJ	LU	1			
14	Carolina Tractor & Equipment 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	04/13/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Carter Hill Farms, LLC	LU	1			
2	Castalia Solar LLC	LU	1			
3	Cates Associates Inc	LU	1			
4	Catherine Willis	LU	1			
5	CB Bladen Solar	LU	1			
6	CBC Alternative Energy LLC (NEW)	LU	1			
7	CBC Alternative Energy LLC (OLD)	LU	1			
8	Cedar Solar LLC	LU	1			
9	Chadbourn Farm, LLC	LU	1			
10	Charlene Abbott	LU	1			
11	Charles Fitzgerald	LU	1			
12	Charles Lewis	LU	1			
13	Chauncey Farm LLC	LU	1			
14	Chei Solar	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	Choco Solar LLC	LU	1			
2	Chocowinity Pet Resort	LU	1			
3	Chocowinity Solar	LU	1			
4	Chocowinity Vet Hospital PLLC	LU	1			
5	Christiansted Port Terminal Corp.	LU	1			
6	Cirrus Solar	LU	1			
7	City of Raleigh Parks Recreation Depat	LU	1			
8	Clara Reed	LU	1			
9	Claudette Wren	LU	1			
10	Clay Emerick	LU	1			
11	Coats Solar, LLC	LU	1			
12	Cohen Farm Solar	LU	1			
13	Constance Burns	LU	1			
14	Corc Solar LLC	LU	1			
	Total					

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1	Cornwall Solar	LU	1			
2	Covey Run Apartments LLC	LU	1			
3	Cox Lake Hydro Electric	LU	1			
4	CPI Roxboro	LU	1			
5	CPI Southport	LU	1			
6	Craig Eury	LU	1			
7	Craven County Wood Energy, LP	LU	1			
8	Crestwood Solar	LU	1			
9	Crockett Farm	LU	1			
10	Currin Solar Farm	LU	1			
11	Custom Packaging Inc	LU	1			
12	Dan Gilbert	LU	1			
13	Danielle Carr	LU	1			
14	Darren Dasburg	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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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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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	David Box	LU	1			
2	David Greune	LU	1			
3	David Tobin	LU	1			
4	Debra Bapat	LU	1			
5	Deep River Hydro	LU	1			
6	Delco Farm	LU	1			
7	Deltec Homes Inc	LU	1			
8	Dement Farm, LLC	LU	1			
9	Dessie Solar Center	LU	1			
10	Detlef Knappe	LU	1			
11	Diana Haran	LU	1			
12	Don Jackson	LU	1			
13	Douglas Brablec	LU	1			
14	DRPFC I 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.
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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	Edward McCraw	LU	1			
11	Elaine Sale	LU	1			
12	Elisabeth Corley	LU	1			
13	Elizabeth Geller	LU	1			
14	Elizabeth Simon-Thomas (Maarten & Eli)	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	04/13/2017	End of 2016/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	Elm Solar	LU	1			
2	Enerdyne Properties LLC	LU	1			
3	EnergyXchange INC	LU	1			
4	Environmental Resources	LU	1			
5	Erwin Farm LLC	LU	1			
6	ESA Four Oaks	LU	1			
7	ESA NC Solar LLC	LU	1			
8	ESA Newton Grove 1 NC LLC	LU	1			
9	ESA Princeton NC	LU	1			
10	ESA RENEWABLES III LLC	LU	1			
11	Eugene Keil	LU	1			
12	Eva Anderson (James Anderson Barn)	LU	1			
13	Eva Anderson (James Anderson House)	LU	1			
14	EWP 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.
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1	Exhibit Court Solar LLC	LU	1			
2	F & D Huebner LLC	LU	1			
3	Faison Solar LLC	LU	1			
4	Farrington Farm LLC	LU	1			
5	Ferguson Solar LLC	LU	1			
6	First Christian Church	LU	1			
7	First Citizens Bank & Trust Co 1.14MW	LU	1			
8	First Citizens Bank & Trust Co 566KW	LU	1			
9	First Congregational Church	LU	1			
10	Floyd Solar	LU	1			
11	FLS Owner 80 LLC	LU	1			
12	FLS Owner II LLC	LU	1			
13	FLS Solar 10 LLC	LU	1			
14	FLS Solar 100 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	04/13/2017	End of 2016/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	FLS Solar 110 LLC	LU	1			
2	FLS Solar 170 LLC	LU	1			
3	FLS Solar 20 LLC (Chatham)	LU	1			
4	FLS Solar 20 LLC - Chatham (FLS Owner	LU	1			
5	FLS Solar 20 LLC (Greensquare)	LU	1			
6	FLS Solar 200, LLC	LU	1			
7	FLS Solar 230, LLC - Warren Place	LU	1			
8	FLS Solar 260 LLC	LU	1			
9	FLS YK Farm LLC	LU	1			
10	Foxfire Farm LLC	LU	1			
11	Franklin Solar 2, LLC	LU	1			
12	Franklin Solar LLC	LU	1			
13	Fresh Air Energy - Carter	LU	1			
14	Fresh Air Energy - Langley	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	04/13/2017	End of 2016/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	Fresh Air Energy - Pecan	LU	1			
2	Fresh Air Energy XXXI - Little River	LU	1			
3	Fresh Air Thornton (Fresh Air XVI LLC)	LU	1			
4	Fuquay Farms, LLC	LU	1			
5	Garrell Solar Farm	LU	1			
6	Gary Kruse (Disaster Restoration Serv)	LU	1			
7	Gary Shaver	LU	1			
8	Gary Spodnick	LU	1			
9	Gaylond Owens	LU	1			
10	Gene Rainey	LU	1			
11	George King	LU	1			
12	Gerald Wehmueller	LU	1			
13	Gerry Cobley	LU	1			
14	Glen Raven 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	04/13/2017	End of 2016/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	Gordon Koncal	LU	1			
2	Grace Evans	LU	1			
3	Grant Todd	LU	1			
4	Granville Solar LLC	LU	1			
5	Greenfield Power GTP One LLC	LU	1			
6	Greg Cumberford	LU	1			
7	Gregory Poole Equip Co	LU	1			
8	Gwendolyn Anderson	LU	1			
9	Happy Solar	LU	1			
10	Harrell's Hill Solar	LU	1			
11	HCE Johnston I, LLC	LU	1			
12	Henry Barnes	LU	1			
13	Hessler 115KW	LU	1			
14	Hessler 153KW	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.
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1	Hew Fulton Farm LLC	LU	1			
2	Hickory Nut Gap Farm LLC	LU	1			
3	Highland Community Solar LLC	LU	1			
4	Highland Craftsmen INC	LU	1			
5	Highland Solar Center	LU	1			
6	Highwater Solar	LU	1			
7	Holstein Holdings	LU	1			
8	Howard Larsen	LU	1			
9	Howard Plemmons	LU	1			
10	Hydrodyne-High Falls	LU	1			
11	Hydrodyne-Little River	LU	1			
12	Ideal Fastner Corp	LU	1			
13	Ingenco Renewables	LU	1			
14	Innovative Solar 10	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Innovative Solar 44 LLC	LU	1			
2	Innovative Solar 48 LLC	LU	1			
3	Innovative Solar 6	LU	1			
4	Innovative Solar 63	LU	1			
5	Innovative Solar 64 LLC	LU	1			
6	Innovative Solar6 P1	LU	1			
7	Innovative Solar6 P2	LU	1			
8	Jack Bennett	LU	1			
9	Jackson & Sons, Inc	LU	1			
10	James Hubbell	LU	1			
11	James O Richard	LU	1			
12	James Thorpe	LU	1			
13	James Young (Asheville Alternative	LU	1			
14	James Young (Asheville Alt Energy)	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	04/13/2017	End of 2016/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	Jane Garvey	LU	1			
2	Janet Dektor	LU	1			
3	Janet Doellgast	LU	1			
4	Jason Hibbets	LU	1			
5	Jason Sprouse	LU	1			
6	Jay Dechesere	LU	1			
7	Jay Lindenmuth	LU	1			
8	Jean Cassidy	LU	1			
9	Jennifer Cole	LU	1			
10	Jennifer Macri	LU	1			
11	Jeri Hilton	LU	1			
12	Jerry Braxton	LU	1			
13	Jerry Sullivan	LU	1			
14	Jessica Larsen (Chris Larsen)	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	04/13/2017	End of 2016/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	Jim Sherrer	LU	1			
2	JoAnn Goddard	LU	1			
3	John Donoghue	LU	1			
4	John Godwin	LU	1			
5	John Hollingsworth	LU	1			
6	John McDermott	LU	1			
7	John Reese	LU	1			
8	John Sorge (Sorge Solar System)	LU	1			
9	Jordan Hydroelectric LLC	LU	1			
10	Joseph Callahan	LU	1			
11	Joseph Ponzi	LU	1			
12	Joy Bisesi	LU	1			
13	JT Hobby & Sons, Inc.	LU	1			
14	Judith Webb	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	04/13/2017	End of 2016/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	Julia Latham	LU	1			
2	K & HB Enterprises LLC - Waynesville	LU	1			
3	K & HB Enterprises LLC - Asheville	LU	1			
4	Karen Gilbert	LU	1			
5	Karen Mallam	LU	1			
6	Karen Redick	LU	1			
7	Karl Werner	LU	1			
8	Kathy Hansinger	LU	1			
9	Kathy Triplett	LU	1			
10	Keen Farm	LU	1			
11	Kelly Daiker	LU	1			
12	Kenansville Solar 2 LLC	LU	1			
13	Kenansville Solar Farm LLC (Heelstone	LU	1			
14	Kenansville Solar LLC (FLS Energy)	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) 04/13/2017	Year/Period of Report End of 2016/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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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	Kenneth Rich	LU	1			
2	Kenneth Solar	LU	1			
3	Kermit Gurley	LU	1			
4	Kevin Ours	LU	1			
5	Kinston Davis Farm	LU	1			
6	Kinston Solar LLC	LU	1			
7	Kirkwall Holdings LLC	LU	1			
8	Kojak farm	LU	1			
9	Kris Coeytaux	LU	1			
10	Kristen Blackley	LU	1			
11	Kristin Petersen	LU	1			
12	L&D Incorporated	LU	1			
13	L&S Waterpower	LU	1			
14	Lake Upchurch Power Inc.	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	04/13/2017	End of 2016/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	Land of the Sky MT (Eden Solar/Innova)	LU	1			
2	Laney Development Inc	LU	1			
3	Lang Solar	LU	1			
4	Langdon Solar	LU	1			
5	Lanier Solar	LU	1			
6	Laurinburg Solar LLC	LU	1			
7	Lawrence Block	LU	1			
8	Lea Romano	LU	1			
9	Lenior Farm 1, LLC	LU	1			
10	Lenior Farm 2, LLC	LU	1			
11	Leon Petty	LU	1			
12	Leonard Bernstein	LU	1			
13	Lewis Rothlein	LU	1			
14	Linda Sweeney	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	04/13/2017	End of 2016/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	Lisa Mangini	LU	1			
2	Lloyd Fitzwater	LU	1			
3	Lumberton Power	LU	1			
4	M B Haynes Corporation 12KW	LU	1			
5	M B Haynes Corporation 24KW	LU	1			
6	Madison Hydro Partners	LU	1			
7	Mahadev Enterprises LLC	LU	1			
8	Manway Farm LLC	LU	1			
9	Marc Parham	LU	1			
10	Margaret Hayes	LU	1			
11	Mark Blessington	LU	1			
12	Mark Parker	LU	1			
13	Mark Traub	LU	1			
14	Marshall's Locksmith Services Inc	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	04/13/2017	End of 2016/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	Martin Creek Farm LLC	LU	1			
2	Matthew Jansohn	LU	1			
3	Maxton Solar 1	LU	1			
4	McCallum Farm	LU	1			
5	McGoogan Farm	LU	1			
6	McKenzie Farm LLC	LU	1			
7	Melinda Solar LLC	LU	1			
8	Meriwether Farm	LU	1			
9	Metropolitan Sewerage	LU	1			
10	Michael Rowland	LU	1			
11	Michael Thorn	LU	1			
12	Michael Walters	LU	1			
13	Mike Stone	LU	1			
14	Mildred Long	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	04/13/2017	End of 2016/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	Mile Farm LLC	LU	1			
2	Mills Anson Farm	LU	1			
3	Miriam Clayton	LU	1			
4	Moncure Farm LLC	LU	1			
5	Montgomery Solar	LU	1			
6	Moorings Farm, LLC	LU	1			
7	Morgan Farm	LU	1			
8	Morton Barlaz	LU	1			
9	MP Wayne County Landfill	LU	1			
10	Mt Olive Farm	LU	1			
11	Mt Olive Farm 2 LLC	LU	1			
12	Mt Olive Solar 1 LLC	LU	1			
13	Munich Motors INC	LU	1			
14	Murdock Solar	LU	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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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.

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	Nancy Pope	LU	1			
2	Nash 58 Farm	LU	1			
3	Nash 64 Farm	LU	1			
4	Nash 97 Solar	LU	1			
5	Nashville Farms LLC	LU	1			
6	Nathan Conroy	LU	1			
7	NC State Museum of Nat Science	LU	1			
8	NCEMC - Flint 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 - Snow Camp Solar	LU	1			
13	NCEMC - Storm Hog Partners	LU	1			
14	NCEMC - Sunny Point	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	04/13/2017	End of 2016/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.

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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	NCEMPA	LU	1			
2	Neil Caudle	LU	1			
3	Neuse River Solar Farm LLC	LU	1			
4	New Bern Farm LLC	LU	1			
5	Nitro Solar LLC	LU	1			
6	North Carolina Solar I LLC	LU	1			
7	North Carolina Solar II LLC	LU	1			
8	North Carolina Solar III Lessee LLC	LU	1			
9	North Nash Farm LLC	LU	1			
10	Oakboro Farm LLC	LU	1			
11	Old Webbs Mill Hydro LLC	LU	1			
12	Onslow Power Producers, LLC	LU	1			
13	Pate Farm LLC	LU	1			
14	Paul Poole	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) 04/13/2017	Year/Period of Report End of 2016/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	Paul Williamson	LU	1			
2	PCIP Solar Lessee LLC	LU	1			
3	PCSP3 Airport LLC	LU	1			
4	Perkins Solar	LU	1			
5	Peter Brezny	LU	1			
6	Pinedale Springs	LU	1			
7	Pohoja Corporation (Kenneth Sheffield)	LU	1			
8	Porter Solar LLC	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					

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	Rachel Orstad	LU	1			
2	Raeford Farm	LU	1			
3	Railroad Farm	LU	1			
4	Railroad Farm 2, 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 Toad A Powatan Road LLC	LU	1			
10	Red Toad II LLC	LU	1			
11	Renewable Power LLC (Foodlion)	LU	1			
12	Richard Muse	LU	1			
13	Rick Suberman	LU	1			
14	Riding Partners INC	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	04/13/2017	End of 2016/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	Riding Partners INC #2	LU	1			
2	Riding Partners INC #3	LU	1			
3	Robert & Phyllis Wooten	LU	1			
4	Robert Beatty	LU	1			
5	Robert Depew	LU	1			
6	Robert Dick	LU	1			
7	Robert Ginsberg	LU	1			
8	Robert Harris	LU	1			
9	Robert Hicks	LU	1			
10	Robert Kellam	LU	1			
11	Robert Wooten	LU	1			
12	Rock Farm LLC	LU	1			
13	Rockingham Solar LLC	LU	1			
14	Roger Gendron	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	04/13/2017	End of 2016/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	Ron Hess	LU	1			
2	Rose Hill Solar LLC	LU	1			
3	Roxboro Farm LLC	LU	1			
4	Roxboro Solar Farm	LU	1			
5	Roy Turnbaugh	LU	1			
6	Royal Solar LLC	LU	1			
7	Sam Rogers	LU	1			
8	Samarcand Solar Farm	LU	1			
9	Sampson Solar LLC	LU	1			
10	Sandy Cross Solar LLC	LU	1			
11	Sarah Cox	LU	1			
12	Sarah Solar LLC	LU	1			
13	SAS - 1200KW	LU	1			
14	SAS Institute Inc	LU	1			
	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	Scott Shackleton	LU	1			
2	SEGY LLC	LU	1			
3	Selma Solar Farm	LU	1			
4	Shaler Stidman	LU	1			
5	Shannon Farm	LU	1			
6	SMB Holding 10 LLC	LU	1			
7	SMB Holdings 5 LLC	LU	1			
8	Snow Hill Solar 2	LU	1			
9	Sol Sencia Ventures LLC (Paul Kazmer)	LU	1			
10	Solar 55 LLC	LU	1			
11	Solarworks RCC LLC	LU	1			
12	Soluga Farm I, LLC	LU	1			
13	Soluga Farm II LLC	LU	1			
14	Soluga Farm III 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	04/13/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Sonne One LLC	LU	1			
2	Soul City Solar	LU	1			
3	South Atlantic Services	LU	1			
4	South Louisburg Solar	LU	1			
5	South Robeson Solar Farm, LLC	LU	1			
6	Southeastern Freight Lines	LU	1			
7	Spicewood Solar Farm	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 Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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	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	04/13/2017	End of 2016/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	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	THMA Venture LLC (Marjorie Burgess)	LU	1			
9	Thomas Reese	LU	1			
10	Thorsten Degenhardt	LU	1			
11	Timothy Forrest	LU	1			
12	Tony Gaddis	LU	1			
13	Town of Warsaw Solar	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	04/13/2017	End of 2016/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	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 Granville Community College	LU	1			
12	Vance Solar 1	LU	1			
13	Vandy LLC	LU	1			
14	Vickers Solar 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	04/13/2017	End of 2016/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	Vicksburg Solar LLC	LU	1			
2	W.E. Partners IV LLC	LU	1			
3	Wadesboro Farm	LU	1			
4	Wadesboro Farm 2	LU	1			
5	Wadesboro Farm 3	LU	1			
6	Wadesboro Solar	LU	1			
7	Wagstaff Farm 1, LLC	LU	1			
8	Wake Tech Innovations Inc	LU	1			
9	Wallace Solar	LU	1			
10	Warren Wilson College	LU	1			
11	Warrenton Farm, LLC	LU	1			
12	Warsaw Solar	LU	1			
13	Warsaw Solar 2 LLC	LU	1			
14	Watts 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	04/13/2017	End of 2016/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	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	Westgate Auto Group LLC	LU	1			
7	Weyerhaesuer NR	LU	1			
8	William Hewitt	LU	1			
9	Wilson Farm 1, LLC	LU	1			
10	Woodland Church Farm	LU	1			
11	Wortham Solar	LU	1			
12	Yanceyville Farm 2 LLC	LU	1			
13	Yanceyville Farm 3	LU	1			
14	Yanceyville 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	04/13/2017	End of 2016/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	ZV Solar 1	LU	1			
2	ZV Solar 3	LU	1			
3	Other < 1MWh Entities	LU	1			
4	Broad River Energy, LLC	LU	1			
5	Broad River Energy, LLC	AD	1			
6	City of Fayetteville (Butler Warner)	OS	see Note 2			
7	City of Fayetteville (Butler Warner)	AD	see Note 2			
8	Southern Company Services	LU	7			
9	PJM Settlements, Inc	OS	188			
10	PJM Settlements, Inc	AD	188			
11	Haywood Electric Membership Corporatin	LF	180			
12	North Carolina Electric Membership C	LF	182			
13	North Carolina Electric Membership Con	AD	182			
14	Duke Energy Carolinas, LLC	OS	190			
	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.
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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	Duke Energy Carolinas, LLC	AD	190			
2	Duke Energy Carolinas, LLC	OS	190			
3	Duke Energy Carolinas, LLC	AD	190			
4	Duke Energy Carolinas, LLC	OS	45			
5	Duke Energy Carolinas, LLC	OS	4			
6	Rock Tenn CP, LLC	EX	4			
7	North Carolina Electric Member Corp.	EX	4			
8	Industrial Power Generation Corp.	EX	4			
9	Other	AD				
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)	
56				3,388		3,388	1
641				49,081		49,081	2
557				34,851		34,851	3
1				51		51	4
175				14,464		14,464	5
4				186		186	6
46				3,511		3,511	7
11,216				748,688		748,688	8
2				76		76	9
8				546		546	10
7				359		359	11
6				303		303	12
16				1,245		1,245	13
9,264				764,805		764,805	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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)	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.
6				293		293	1
6				364		364	2
4,268				350,366		350,366	3
10,059				674,829		674,829	4
8,288				684,550		684,550	5
17				1,169		1,169	6
3,203				262,615		262,615	7
78				3,324		3,324	8
259				12,506		12,506	9
715				54,725		54,725	10
330				25,299		25,299	11
647				49,518		49,518	12
210				13,164		13,164	13
1				32		32	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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)	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.
10,356				698,970		698,970	1
9,899				664,918		664,918	2
7				448		448	3
14				1,035		1,035	4
17				1,323		1,323	5
1				70		70	6
9,741				654,357		654,357	7
106				6,405		6,405	8
11				543		543	9
35				2,186		2,186	10
34				2,098		2,098	11
29,732				1,978,563		1,978,563	12
6				285		285	13
10				815		815	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
3,155				261,583		261,583	1
4				256		256	2
628				48,086		48,086	3
1				46		46	4
2,518				126,166		126,166	5
9,684				568,949		568,949	6
9,666				648,208		648,208	7
64,559				3,910,491		3,910,491	8
9,119				752,170		752,170	9
9,902				662,370		662,370	10
9,565				641,464		641,464	11
9,228				759,028		759,028	12
7				329		329	13
9,615				643,721		643,721	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
7				352		352	1
6				323		323	2
9,742				804,484		804,484	3
2,302				183,669		183,669	4
7				373		373	5
7,915				538,134		538,134	6
12,126				889,480		889,480	7
5				357		357	8
13				677		677	9
3,112				208,597		208,597	10
61				4,281		4,281	11
911				57,034		57,034	12
356				22,294		22,294	13
335				20,953		20,953	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
7				400		400	1
3,751				310,884		310,884	2
4				206		206	3
14				710		710	4
7,536				526,851		526,851	5
4,242				350,326		350,326	6
1,364				104,457		104,457	7
10,177				685,254		685,254	8
9,541				782,986		782,986	9
9				566		566	10
9				462		462	11
3				160		160	12
9,126				595,606		595,606	13
9,805				656,675		656,675	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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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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)	
9,757				653,943		653,943	1
12				621		621	2
8,671				580,580		580,580	3
4				235		235	4
438				35,774		35,774	5
9,169				611,904		611,904	6
38				2,382		2,382	7
9				464		464	8
6				352		352	9
14				872		872	10
6,533				441,868		441,868	11
3,254				216,235		216,235	12
2				123		123	13
302				25,242		25,242	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
119				10,335		10,335	1
9				474		474	2
845				68,448		68,448	3
315,950				24,749,531		24,749,531	4
518,339				40,406,968		40,406,968	5
8				503		503	6
322,946				19,027,967		19,027,967	7
6,983				470,686		470,686	8
9,414				618,087		618,087	9
8,746				548,211		548,211	10
275				21,068		21,068	11
6				283		283	12
3				159		159	13
6				313		313	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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 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				496		496	1
7				365		365	2
4				212		212	3
5				255		255	4
809				65,859		65,859	5
6,212				422,269		422,269	6
76				3,782		3,782	7
9,140				752,411		752,411	8
9,512				785,626		785,626	9
4				206		206	10
6				292		292	11
4				220		220	12
7				368		368	13
26				1,607		1,607	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
3,744				308,523		308,523	1
9,344				771,836		771,836	2
9,675				799,171		799,171	3
1				38		38	4
4,054				332,425		332,425	5
14				862		862	6
9,841				811,668		811,668	7
1				31		31	8
7				432		432	9
2				149		149	10
2				85		85	11
15				774		774	12
6				301		301	13
5				347		347	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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)	
9,731				653,773		653,773	1
2,935				132,752		132,752	2
11				570		570	3
7				347		347	4
7,833				511,430		511,430	5
9,555				619,079		619,079	6
677				51,824		51,824	7
3,448				284,992		284,992	8
9,775				637,372		637,372	9
1,605				100,477		100,477	10
7				336		336	11
9				449		449	12
2				86		86	13
862				55,004		55,004	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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)	
617				51,022		51,022	1
35				2,177		2,177	2
3,655				237,774		237,774	3
1,664				127,425		127,425	4
178				9,416		9,416	5
19				1,229		1,229	6
1,264				64,212		64,212	7
661				33,066		33,066	8
16				790		790	9
4,022				275,303		275,303	10
2,458				190,554		190,554	11
118				9,855		9,855	12
688				43,045		43,045	13
6,845				565,450		565,450	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
3,147				260,411		260,411	1
3,169				212,409		212,409	2
88				6,748		6,748	3
39				2,996		2,996	4
373				28,522		28,522	5
6,499				436,667		436,667	6
9,049				607,431		607,431	7
8,938				594,275		594,275	8
77				4,837		4,837	9
10,305				688,900		688,900	10
3,694				306,454		306,454	11
3,152				261,777		261,777	12
10,344				694,020		694,020	13
10,422				698,544		698,544	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
10,295				688,492		688,492	1
9,683				649,261		649,261	2
8,963				606,357		606,357	3
9,106				750,212		750,212	4
7,354				607,433		607,433	5
13				652		652	6
13				665		665	7
3				217		217	8
15				953		953	9
4				256		256	10
4				186		186	11
3				134		134	12
8				427		427	13
519				32,478		32,478	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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) 04/13/2017	End of 2016/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 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				695		695	1
3				162		162	2
4				278		278	3
4,552				348,516		348,516	4
319				19,979		19,979	5
5				271		271	6
272				17,055		17,055	7
5				321		321	8
7,650				511,461		511,461	9
10,048				829,974		829,974	10
3,886				259,885		259,885	11
4				195		195	12
137				8,543		8,543	13
198				15,184		15,184	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
10,489				702,023		702,023	1
1				35		35	2
63				3,461		3,461	3
8				430		430	4
7,825				525,924		525,924	5
6,390				431,136		431,136	6
36,191				1,871,444		1,871,444	7
8				403		403	8
13				665		665	9
1,023				81,799		81,799	10
306				24,138		24,138	11
273				20,919		20,919	12
44,676				3,045,143		3,045,143	13
3,041				201,386		201,386	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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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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)	
9,196				617,677		617,677	1
9,572				641,693		641,693	2
1,602				106,329		106,329	3
7,427				497,186		497,186	4
9,612				644,581		644,581	5
1,691				112,385		112,385	6
3,696				244,659		244,659	7
4				190		190	8
31				1,941		1,941	9
8				491		491	10
1				66		66	11
5				320		320	12
41				2,078		2,078	13
56				3,007		3,007	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
7				429		429	1
6				291		291	2
2				109		109	3
8				391		391	4
7				343		343	5
5				305		305	6
5				340		340	7
4				196		196	8
9				445		445	9
3				194		194	10
10				634		634	11
6				303		303	12
8				533		533	13
8				407		407	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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.
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)	
5				243		243	1
7				347		347	2
2				88		88	3
17				882		882	4
7				467		467	5
10				497		497	6
6				287		287	7
9				450		450	8
11,312				756,399		756,399	9
6				328		328	10
9				464		464	11
2				94		94	12
631				50,993		50,993	13
13				673		673	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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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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				871		871	1
36				2,255		2,255	2
34				2,141		2,141	3
5				266		266	4
17				843		843	5
3				118		118	6
12				592		592	7
3				152		152	8
6				295		295	9
10,228				683,661		683,661	10
4				216		216	11
3,664				245,225		245,225	12
8,108				670,233		670,233	13
3,590				297,106		297,106	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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				252		252	1
5,324				358,107		358,107	2
3				154		154	3
3				149		149	4
9,579				625,984		625,984	5
4,016				330,946		330,946	6
9,554				639,838		639,838	7
6,322				430,749		430,749	8
7				465		465	9
8				384		384	10
12				603		603	11
11				660		660	12
1,290				105,061		105,061	13
974				49,721		49,721	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
96,493				5,498,869		5,498,869	1
13				1,012		1,012	2
9,936				670,439		670,439	3
9,987				668,559		668,559	4
2,925				196,117		196,117	5
3,692				247,670		247,670	6
12				610		610	7
5				294		294	8
8,716				719,413		719,413	9
6,859				578,249		578,249	10
7				331		331	11
3				129		129	12
3				191		191	13
4				298		298	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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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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				217		217	1
11				536		536	2
52,283				3,997,968		3,997,968	3
15				1,156		1,156	4
37				2,818		2,818	5
2,080				127,797		127,797	6
14				1,079		1,079	7
10,950				733,241		733,241	8
8				407		407	9
6				298		298	10
5				265		265	11
6				301		301	12
1				63		63	13
17				1,318		1,318	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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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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)	
5,657				466,776		466,776	1
3				170		170	2
2,448				162,512		162,512	3
9,403				774,868		774,868	4
10,070				676,276		676,276	5
7,854				522,593		522,593	6
8,817				586,297		586,297	7
2,977				174,878		174,878	8
17				1,159		1,159	9
19				1,221		1,221	10
3				152		152	11
2				77		77	12
4				209		209	13
4				197		197	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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 Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,733				802,455		802,455	1
6,244				423,652		423,652	2
6				285		285	3
6,465				533,547		533,547	4
41,521				2,832,878		2,832,878	5
8,857				729,782		729,782	6
10,574				709,240		709,240	7
4				200		200	8
11,708				711,969		711,969	9
10,572				874,582		874,582	10
9,228				760,457		760,457	11
9,404				631,907		631,907	12
7				345		345	13
7,885				528,633		528,633	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
4				283		283	1
9,672				798,111		798,111	2
7,831				647,857		647,857	3
8,305				558,059		558,059	4
3,826				316,896		316,896	5
4				201		201	6
10				491		491	7
2,434				117,915		117,915	8
1,326				90,295		90,295	9
2,805				196,044		196,044	10
4,751				274,532		274,532	11
9,077				510,453		510,453	12
2,978				201,990		201,990	13
204				10,660		10,660	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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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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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)	
152,512				10,748,970		10,748,970	1
1				60		60	2
1,866				116,855		116,855	3
9,234				761,059		761,059	4
8,810				587,981		587,981	5
2,797				214,136		214,136	6
2,355				196,139		196,139	7
9,234				762,823		762,823	8
10,842				728,324		728,324	9
9,476				618,603		618,603	10
59				4,211		4,211	11
12,369				895,041		895,041	12
9,431				777,715		777,715	13
3				144		144	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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) 04/13/2017	End of 2016/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.
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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)	
1				76		76	1
1,839				115,114		115,114	2
4,677				358,118		358,118	3
484				25,343		25,343	4
4				261		261	5
64				4,383		4,383	6
5				235		235	7
8,603				506,475		506,475	8
276				21,528		21,528	9
6,180				512,653		512,653	10
6,096				502,672		502,672	11
6,574				543,516		543,516	12
547				41,899		41,899	13
6,100				407,876		407,876	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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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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)	
2				115		115	1
9,357				774,017		774,017	2
9,384				773,947		773,947	3
10,192				843,889		843,889	4
5				292		292	5
1				31		31	6
15				782		782	7
9,390				775,596		775,596	8
4,172				272,186		272,186	9
689				52,719		52,719	10
273				17,094		17,094	11
3				154		154	12
4				178		178	13
9				481		481	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
8				420		420	1
4				197		197	2
2				72		72	3
23				1,158		1,158	4
7				372		372	5
5				333		333	6
4				192		192	7
7				334		334	8
2				124		124	9
6				297		297	10
12				602		602	11
9,446				776,087		776,087	12
9,881				659,310		659,310	13
3				149		149	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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 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				600		600	1
3,749				305,436		305,436	2
9,628				794,700		794,700	3
9,080				570,042		570,042	4
6				284		284	5
8,996				603,530		603,530	6
9				439		439	7
9,714				801,860		801,860	8
4,145				261,393		261,393	9
2,245				171,869		171,869	10
1				48		48	11
8,550				575,748		575,748	12
1,835				89,376		89,376	13
1,460				88,396		88,396	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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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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				450		450	1
8				493		493	2
9,785				808,394		808,394	3
3				175		175	4
9,239				762,854		762,854	5
20				1,358		1,358	6
16				1,037		1,037	7
3,943				323,916		323,916	8
102				7,120		7,120	9
3,183				263,338		263,338	10
621				47,527		47,527	11
9,505				619,282		619,282	12
9,532				623,013		623,013	13
10,789				724,042		724,042	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
10,330				691,688		691,688	1
5,767				386,606		386,606	2
3,251				211,603		211,603	3
2,230				148,180		148,180	4
7,880				642,279		642,279	5
1,855				128,460		128,460	6
8,881				580,063		580,063	7
8,951				602,909		602,909	8
2,337				127,418		127,418	9
30				1,547		1,547	10
4				196		196	11
3,726				252,786		252,786	12
9,388				774,374		774,374	13
9				441		441	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
13				654		654	1
3,992				231,030		231,030	2
9,245				621,110		621,110	3
14				725		725	4
8,962				736,147		736,147	5
9,505				786,059		786,059	6
1,643				102,834		102,834	7
9,756				806,454		806,454	8
298				18,673		18,673	9
10,177				680,189		680,189	10
51				4,025		4,025	11
5				234		234	12
2				74		74	13
10,089				675,955		675,955	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
6,036				412,072		412,072	1
8				398		398	2
31				1,946		1,946	3
17				879		879	4
19				1,215		1,215	5
567				43,388		43,388	6
12				598		598	7
4				250		250	8
6				288		288	9
8				399		399	10
3				170		170	11
12				625		625	12
806				54,000		54,000	13
2				111		111	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
20,806				1,334,906		1,334,906	1
7				352		352	2
10				494		494	3
9,360				549,888		549,888	4
7,241				486,205		486,205	5
7,474				501,682		501,682	6
9,752				651,750		651,750	7
1,885				127,150		127,150	8
6				320		320	9
63,654				3,628,273		3,628,273	10
1				71		71	11
8,941				603,068		603,068	12
11				673		673	13
4,094				265,809		265,809	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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	04/13/2017	End of 2016/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.
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)	
9,130				610,198		610,198	1
7				418		418	2
6,428				418,140		418,140	3
5,262				358,795		358,795	4
7,776				543,986		543,986	5
3,501				229,759		229,759	6
9,866				815,154		815,154	7
479				36,646		36,646	8
3,605				297,399		297,399	9
10				514		514	10
7,897				650,234		650,234	11
3,575				293,485		293,485	12
3,402				281,710		281,710	13
9,048				746,966		746,966	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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				676		676	1
9,279				767,045		767,045	2
9,807				807,876		807,876	3
8,937				736,430		736,430	4
9,363				626,272		626,272	5
119				9,139		9,139	6
343				12,830		12,830	7
16				800		800	8
8,865				729,127		729,127	9
10,379				696,055		696,055	10
2,447				145,898		145,898	11
9,755				637,656		637,656	12
9,834				657,446		657,446	13
9,536				787,015		787,015	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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)	
5,364				367,228		367,228	1
8,412				564,369		564,369	2
1				53		53	3
1,220,230			43,745,872	52,996,273		96,742,145	4
				3,061		3,061	5
10,988			12,751,350	767,562		13,518,912	6
			200	20		220	7
1,155,401			12,965,684	33,572,312		46,537,996	8
27,178				672,170		672,170	9
				62		62	10
			353,248			353,248	11
307,667			35,858,656	12,506,681		48,365,337	12
				358		358	13
1,235,026				35,643,268		35,643,268	14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

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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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)	
-247				-45,501		-45,501	1
57,733					2,671,081	2,671,081	2
62					993	993	3
1,492				66,043		66,043	4
				-4,372		-4,372	5
12,055				336,758		336,758	6
3,741				97,769		97,769	7
1,427				32,504		32,504	8
156							9
							10
							11
							12
							13
							14
7,424,717			105,675,010	377,234,497	2,672,074	485,581,581	

Schedule Page: 326 Line No.: 1 Column: a

The number " (1) " notation designates FERC approved Tariff and/or Rate Schedule as on file with the Commission.

Schedule Page: 326 Line No.: 1 Column: k

For the DE Progress Non-Utility Generating Systems, the qualified facilities are paid on a $/MWh basis; therefore, these charges are being reported as energy.

Schedule Page: 326.38 Line No.: 3 Column: a

Qualified non-utility generating systems that generated less than 1 MWh were consolidated on this line. Below is the detail by facility:

Counterparty Name	MWH	Energy Charge
Barbara Howard	0.231	$9.54
Elaine Manning	0.292	$14.35
Evergreen Landscaping Ser	0.083	$3.93
Grant Ingersoll	0.176	$8.74
Rocky River Hydro	0.013	$1.53
William Harlan	0.014	$0.60
William Kelly	0.268	$14.04
Totals	1.077	$52.73
Rounded Totals	**1 MWh**	**$53**

Schedule Page: 326.38 Line No.: 6 Column: a

Note (2): Purchases are pursusant to a non-FERC jurisdictional tolling agreement.

Schedule Page: 326.38 Line No.: 7 Column: a

Note (2): Purchases are pursuant to a non-FERC jurisdictional tolling agreement.

Schedule Page: 326.38 Line No.: 14 Column: a

Duke Energy Carolinas is an affiliate of Duke Energy Progress, LLC.

Schedule Page: 326.39 Line No.: 1 Column: a

Duke Energy Carolinas is an affiliate of Duke Energy Progress, LLC.

Schedule Page: 326.39 Line No.: 2 Column: a

Duke Energy Carolinas is an affiliate of Duke Energy Progrss, LLC.

Schedule Page: 326.39 Line No.: 3 Column: a

Duke Energy Carolinas is an affiliate of Duke Energy Progress, LLC.

Schedule Page: 326.39 Line No.: 4 Column: a

Duke Energy Carolinas is an affiliate of Duke Energy Progress, LLC.

Schedule Page: 326.39 Line No.: 5 Column: a

Duke Energy Carolinas, LLC is an affiliate of Duke Energy Progress, LLC.

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	04/13/2017	End of 2016/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	Pennsylvania-New Jersey-Maryland-	Carolina Power & Light Company	OLF
2	Southeastern Power Administration	Tennessee Valley Authority	Carolina Power & Light Company	OLF
3	Duke Energy Carolinas	Duke Energy Corporation	Pennsylvania-New Jersey-Maryland-	OS
4	Cargill	various	various	NF
5	City of Camden	various	various	FNO
6	Calpine	various	various	NF
7	Craven County Wood Energy	various	various	OS
8	Duke Energy Carolinas	various	various	NF
9	Elizabethtown Power L.L.C.	various	various	OS
10	Exelon	various	various	SFP
11	Fayetteville Public Works Commission	various	various	FNO
12	French Broad Electric Membership	various	various	FNO
13	Haywood Electric Membership Coroporation	various	various	FNO
14	Industrial Power Generating Company L.L.C	various	various	LFP
15	Industrial Power Generating Company L.L.C	various	various	OS
16	Lumberton Power L.L.C.	various	various	OS
17	North Carolina Electric Membership	various	various	LFP
18	North Carolina Electric Membership	various	various	FNO
19	NC Eastern Municipal Power Agency	various	various	FNO
20	North Carolina Municipal Power Agency	various	various	SFP
21	Piedmont Electric Membership Corporation	various	various	FNO
22	The Energy Authority	various	various	NF
23	Town of Sharpsburg N.C.	various	various	FNO
24	Town of Stantonsburg N.C.	various	various	FNO
25	Town of Black Creek N.C.	various	various	FNO
26	Town of Lucama N.C.	various	various	FNO
27	Uwharrie Mntn Renewable Energy	various	various	OS
28	Wholesale Power Marketing	various	various	SFP
29	Town of Waynesville	various	various	FNO
30	Town of Winterville	various	various	FNO
31	QUALIFYING FACILITIES			
32	FERC AUDIT ACCRUAL TO ADJUST			
33	FERC AUDIT ACCRUAL TO ADJUST			
34	Accrue DEP Transmission Revenue for			
	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	04/13/2017	End of 2016/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 Classification (d)
1	FERC AUDIT ACCRUAL TO ADJUST			
2	2014 OATT SETTLEMENT DEP			
3	ACCRUAL REVERSAL			
4	FERC AUDIT ACCRUAL REVERSAL			
5	2014 DEP OATT SETTLEMENT ACCRUAL			
6	2015 DEP OATT SETTLEMENT ACCRUAL			
7	ACCRUAL FOR THE QUALIFING			
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				
	TOTAL			

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)	MegaWatt Hours Delivered (j)	Line No.
RS127	PJM	CPLE	280	195,180	185,391	1
RS126	TVA	CPLW	48	18,363	17,990	2
RS187	DUKE	PJM				3
JointOATT/230	YAD	PJM	15,960	676,570	666,473	4
JointOATT/309	CPLE	CPLE	451			5
JointOATT	CPLE	CPLE				6
JointOATT/271	CPLE	CPLE				7
JointOATT/11	various	various	610,317			8
JointOATT/204	CPLE	PJM				9
						10
JointOATT/246	CPLE	CPLE	4,375			11
JointOATT/248	CPLW	CPLW	952			12
JointOATT/300	CPLW	CPLW	367			13
JointOATT/288	CPLE	CPLE	174			14
JointOATT/288	CPLE	CPLE				15
JointOATT/205	CPLE	PJM				16
JointOATT/256	CPLE	DUKE	4,517			17
JointOATT/134	CPLE	CPLE	21,817			18
JointOATT/268	CPLE	CPLE	12,551			19
JointOATT/29	CPLE	PJM				20
JointOATT/322	CPLE	CPLE	268			21
JointOATT/68	PJM	SC	4,343			22
JointOATT/296	CPLE	CPLE	44			23
JointOATT/295	CPLE	CPLE	51			24
JointOATT/293	CPLE	CPLE	31			25
JointOATT/294	CPLE	CPLE	51			26
JointOATT/331	CPLE	CPLE				27
						28
JointOATT/303	CPLW	CPLW	159			29
JointOATT/321	CPLE	CPLE	135			30
			338			31
						32
						33
						34
			677,229	**890,113**	**869,854**	

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	04/13/2017	End of 2016/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.
						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
			677,229	**890,113**	**869,854**	

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.
1,354,721			1,354,721	1
236,692			236,692	2
3,565,498			3,565,498	3
518,370		46,369	564,739	4
628,310		60,520	688,830	5
798		68	866	6
		10,500	10,500	7
107,373		9,711	117,085	8
		7,200	7,200	9
23,633		2,029	25,662	10
6,138,038		578,807	6,716,845	11
1,320,858		188,324	1,509,182	12
505,971		66,395	572,366	13
101,088		9,022	110,110	14
		2,700	2,700	15
		4,800	4,800	16
2,477,443		215,644	2,693,087	17
30,261,116		-605,739	29,655,377	18
17,685,425		1,574,830	19,260,255	19
786,359		70,153	856,512	20
371,779		63,096	434,875	21
24,806		2,327	27,133	22
62,822		10,411	73,233	23
71,003		11,428	82,431	24
44,474		8,771	53,244	25
68,582		10,922	79,504	26
		5,052	5,052	27
715		100	815	28
220,470		28,121	248,589	29
186,762		25,060	211,822	30
				31
-152,683			-152,683	32
-61,742			-61,742	33
281,000			281,000	34
65,143,209	**0**	**2,406,621**	**67,549,828**	

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	04/13/2017	End of 2016/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.
-1,302,000			-1,302,000	1
-643,037			-643,037	2
-281,000			-281,000	3
-1,302,000			-1,302,000	4
1,357,605			1,357,605	5
-505,852			-505,852	6
989,812			989,812	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
65,143,209	**0**	**2,406,621**	**67,549,828**	

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	04/13/2017	End of 2016/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					
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14					
15					
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32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	972,167	951,607			761	761
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		972,167	951,607			761	761

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	04/13/2017	End of 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	789,764
2	Nuclear Power Research Expenses	1,329,509
3	Other Experimental and General Research Expenses	118,621
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	-33,369,868
7	Allocated Incentives	5,661
8	Suspense Clearing	-785,599
9	Environmental Accrual Adjustment	-5,575,662
10	Consultants and Contract Services	890,873
11	Labor Accrual	2,179,004
12	Restricted Stock Units	349,977
13	Other Contracts	7,841
14	Allocated Labor	51,453
15	Travel	122,136
16	Direct Purchase Allocations	159,321
17	Personal Vehicle Mileage Reimbursement	4,948
18	Postage & Freight	113,537
19	Rent	26,733
20	Sponsorships	90
21	Miscellaneous < $5k	4,929
22	Moving Expenses	3,759,745
23	Dues and Subscriptions to various organizations	278,654
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
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41		
42		
43		
44		
45		
46	TOTAL	-29,538,333

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	04/13/2017	End of 2016/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			31,071,436		31,071,436
2	Steam Production Plant	100,794,244				100,794,244
3	Nuclear Production Plant	168,390,295				168,390,295
4	Hydraulic Production Plant-Conventional	3,263,041				3,263,041
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	72,154,052				72,154,052
7	Transmission Plant	40,048,151				40,048,151
8	Distribution Plant	204,148,669				204,148,669
9	Regional Transmission and Market Operation					
10	General Plant	15,688,715				15,688,715
11	Common Plant-Electric					
12	TOTAL	604,487,167		31,071,436		635,558,603

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	04/13/2017	End of 2016/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	Steam Production Plant						
14	Asheville #1 310-316	237,203	72.27	-5.09	1.77	Various	19.52
15	Asheville #2 310-316	216,465	80.56	-5.11	1.28	Various	21.06
16	Mayo 310-316	1,177,378	74.25	-5.00	2.91	Various	22.69
17	Roxboro #1 310-316	299,513	72.50	-4.60	3.79	Various	19.83
18	Roxboro #2 310-316	382,820	80.56	-5.11	2.37	Various	19.86
19	Roxboro #3 310-316	484,651	68.13	-6.00	3.09	Various	22.33
20	Roxboro #4 310-316	467,835	78.33	-5.40	0.45	Various	21.84
21	Roxboro Common	398,492	80.56	-5.11	3.26	Various	22.57
22	Shared - Fossil	1,583	106.67	-4.00	3.40	Various	28.43
23	SCR - Asheville #1	3,863	70.00	-10.00	35.45	Various	3.00
24	SCR - Asheville #2	1,927	70.00	-10.00	34.61	Various	2.61
25	SCR - Mayo	7,429	70.00	-10.00	19.19	Various	5.56
26	SCR - Roxboro #1	7,925	70.00	-10.00	11.30	Various	9.00
27	SCR - Roxboro #2	5,857	70.00	-10.00	19.82	Various	5.46
28	SCR - Roxboro #3	6,472	70.00	-10.00	20.02	Various	5.31
29	SCR - Roxboro #4	7,262	70.00	-10.00	13.62	Various	7.65
30							
31	Nuclear Production Plan						
32	Brunswick #1 320-235	1,425,483	56.94	-5.21	2.65	Various	22.35
33	Brunswick #2 320-325	1,321,081	55.36	-5.84	1.95	Various	20.91
34	Harris 320-325	4,101,802	50.36	-5.04	1.62	Various	29.62
35	Harris Disallowance	-551,297			1.20	Various	
36	Robinson #2 320-325	1,230,304	55.42	-5.78	2.48	Various	18.05
37							
38	Hydro Production Plant						
39	Blewett 330-336	27,650	66.33	-1.08	3.09	Various	34.35
40	Marshall 330-336	12,584	67.57	-0.93	2.94	Various	31.33
41	Tillery 330-336	27,013	66.33	-1.08	2.86	Various	35.15
42	Walters 330-336	52,325	67.57	-0.93	2.75	Various	20.45
43							
44	Other Production Plant						
45	Asheville CT	95,239	41.33	-1.65	2.26	Various	24.13
46	Blewett CT	13,461	41.33	-1.65	2.37	Various	11.36
47	Camp Lejeune Solar	18,200	44.00	-3.50	4.00	Various	25.00
48	Darlington CT	139,821	40.92	-1.40	2.60	Various	14.09
49	Elm City Solar	47,886	44.00	-3.50	4.00	Various	25.00
50	Fayetteville Solar	31,621	44.00	-3.50	4.00	Various	25.00

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	04/13/2017	End of 2016/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	Lee (Wayne County) CT	274,776	35.43	-1.41	2.77	Various	27.26
13	Lee CC	689,233	41.33	-1.65	2.38	Various	40.00
14	Smith CC	486,224	41.33	-1.65	2.38	Various	40.00
15	Smith CT	531,278	41.23	-1.68	2.56	Various	27.18
16	Sutton CC	533,906	41.33	-1.65	2.38	Various	40.00
17	Sutton CT	12,445	41.33	-1.65	0.20	Various	9.83
18	Warsaw Solar	86,195	44.00	-3.50	4.00	Various	25.00
19	Weatherspoon CT	23,166	41.33	-1.65	0.37	Various	13.30
20							
21	Transmission Plant						
22	350 Land and land right	176,855	75.00		1.17	R3	50.59
23	352 Structures and impr	88,263	60.00	-10.00	1.76	R3	43.59
24	353 Station equipment	960,512	60.00	-15.00	1.88	L1	48.27
25	354 Towers and fixtures	60,419	75.00	-19.00	1.16	R3	46.94
26	355 Poles and fixtures	671,528	42.00	-20.00	1.95	R2	30.81
27	356 Overhead conductors	485,261	70.00	-17.00	1.22	R3	50.03
28	359 Roads and Trials	313	75.00		1.37	R3	65.07
29							
30	Distribution Plant						
31	360 Land and land right	23,241	55.00		1.68	R2	37.30
32	361 Structures and impr	105,934	48.00	-15.00	2.08	L1	38.65
33	362 Station equipment	579,863	49.00	-10.00	1.91	R1	38.67
34	364 Poles, towers, and	731,025	40.00	-115.00	5.48	R2	27.73
35	365 Overhead conductors	1,028,698	40.00	-85.00	4.88	R1.5	28.11
36	366 Underground conduit	186,908	45.00	-10.00	2.42	S4	32.68
37	367 Underground conduct	1,032,677	28.00	-5.00	3.81	R5	16.89
38	368 Line transformers	974,384	38.00		2.37	R2	25.28
39	369 Services	489,048	49.00	-30.00	2.21	R2.5	36.13
40	370 Meters	199,758	20.00	-15.00	6.91	R2	10.92
41	371 Installations on cu	281,989	18.00	-10.00	3.74	S2	9.62
42	373 Street lighting and	185,475	37.50	-10.00	2.45	S0.5	25.38
43							
44	General Plant						
45	390 Structures and impr	126,798	45.00	-5.00	2.42	R2	34.07
46	391 Office furniture an	54,071	16.67		6.56	L1	8.84
47	391 Office furniture an	1,890	45.00	-5.00	16.69	S6	
48	392 Transportation equi	100,990	11.00	10.00	11.58	L2	6.77
49	393 Stores equipment	3,593	25.00		6.71	S6	11.27
50	394 Tools, shop and gar	48,797	38.00		2.84	S6	28.21

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	04/13/2017	End of 2016/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	395 Laboratory equipmen	7,266	15.00		9.15	S6	5.11
13	396 Power operated equi	2,690	12.00		16.91	S6	3.93
14	397 Communication Equip	225,569	27.00	-3.00	2.15	L0.5	19.71
15	398 Miscellaneous equip	27,085	35.00		2.87	R5	24.72
16							
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Schedule Page: 336 Line No.: 3 Column: b

Depreciation rates do not include nuclear decommissioning amortization. The portion for nuclear decommissioning amortization accrued in 2016 to Account 403 - Depreciation Expense was $12,841,497.

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	04/13/2017	End of 2016/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)	595,603		595,603	1,439,376
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	1,540,109		1,540,109	
13					
14	Annual Charges Assessed by the NC Utilities				
15	Commission as required by Senate Bill 1320	4,110,202		4,110,202	
16					
17	Annual Charges Assessed by the SC Public				
18	Service Commission	781,706		781,706	
19					
20	Rate case expenses related to 2013				
21	SC Public Service Commission rate case filing	467,936		467,936	
22					
23	Other				
24					
25					
26					
27					
28					
29					
30					
31					
32					
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45					
46	TOTAL	7,495,556		7,495,556	1,439,376

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	04/13/2017	End of 2016/Q4

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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
							5
							6
				182.3	595,603	843,773	7
							8
							9
							10
							11
Electric	928	1,540,109					12
							13
							14
Electric	928	4,110,202					15
							16
							17
Electric	928	781,706					18
							19
							20
Electric	928	467,936					21
							22
							23
							24
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							45
		6,899,953			595,603	843,773	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	04/13/2017	End of 2016/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		Others (less than $50K each)
10		
11	(4) Research Support to Others	Alternative Energy (Advanced Energy Research)
12		
13		
14	(5) Total Cost Incurred	
15		
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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
118,621		930.7	118,621		2
					3
118,621			118,621		4
					5
					6
	6,283,570	Various	6,283,570		7
	655,694	524	655,694		8
	99,015	Various	99,015		9
					10
	1,329,509	930.8	1,329,509		11
					12
					13
	8,367,788		8,367,788		14
					15
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					17
					18
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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	04/13/2017	End of 2016/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	223,993,089		
4	Transmission	7,711,394		
5	Regional Market			
6	Distribution	20,912,819		
7	Customer Accounts	18,551,349		
8	Customer Service and Informational	2,680,907		
9	Sales	3,799,568		
10	Administrative and General	121,047,871		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	398,696,997		
12	Maintenance			
13	Production	169,277,596		
14	Transmission	8,414,274		
15	Regional Market			
16	Distribution	45,780,133		
17	Administrative and General	269,048		
18	TOTAL Maintenance (Total of lines 13 thru 17)	223,741,051		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	393,270,685		
21	Transmission (Enter Total of lines 4 and 14)	16,125,668		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	66,692,952		
24	Customer Accounts (Transcribe from line 7)	18,551,349		
25	Customer Service and Informational (Transcribe from line 8)	2,680,907		
26	Sales (Transcribe from line 9)	3,799,568		
27	Administrative and General (Enter Total of lines 10 and 17)	121,316,919		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	622,438,048	3,727,411	626,165,459
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	04/13/2017	End of 2016/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)	622,438,048	3,727,411	626,165,459
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	129,346,102	13,212,329	142,558,431
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	129,346,102	13,212,329	142,558,431
72	Plant Removal (By Utility Departments)			
73	Electric Plant	21,203,652		21,203,652
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	21,203,652		21,203,652
77	Other Accounts (Specify, provide details in footnote):			
78	Other Work in Progress	594,687		594,687
79	Other Accounts	3,113,696		3,113,696
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,708,383		3,708,383
96	TOTAL SALARIES AND WAGES	776,696,185	16,939,740	793,635,925

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/13/2017	Year/Period of Report End of 2016/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	04/13/2017	End of 2016/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)	190,070	189,825	189,898	672,232
3	Net Sales (Account 447)	283,838	2,768,792	3,991,842	4,042,501
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
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46	TOTAL	473,908	2,958,617	4,181,740	4,714,733

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	04/13/2017	End of 2016/Q4

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				40,758	MWH	1,487,672
2	Reactive Supply and Voltage				346,780	MWH	3,079,432
3	Regulation and Frequency Response						
4	Energy Imbalance	5,168	MWH	130,271	2,853	MWH	96,110
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	5,168		130,271	390,391		4,663,214

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	04/13/2017	End of 2016/Q4

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	13,723	19	8	9,262	4,135	326			
2	February	13,779	11	8	9,561	3,892	326			
3	March	10,981	3	8	7,792	2,863	326			
4	Total for Quarter 1				26,615	10,890	978			
5	April	10,436	6	8	7,386	2,724	326			
6	May	11,180	26	18	7,913	2,941	326			
7	June	13,195	22	17	9,157	3,657	381			
8	Total for Quarter 2				24,456	9,322	1,033			
9	July	14,355	26	16	9,896	4,078	381			
10	August	14,251	15	17	9,842	4,028	381			
11	September	13,117	8	17	9,093	3,643	381			
12	Total for Quarter 3				28,831	11,749	1,143			
13	October	10,592	19	17	7,660	2,551	381			
14	November	11,351	23	8	7,904	3,066	381			
15	December	13,562	16	8	9,467	3,714	381			
16	Total for Quarter 4				25,031	9,331	1,143			
17	Total Year to Date/Year				104,933	41,292	4,297			

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	04/13/2017	End of 2016/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	04/13/2017	End of 2016/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)	43,867,827
3	Steam	11,630,042			
4	Nuclear	29,333,963	23	Requirements Sales for Resale (See instruction 4, page 311.)	18,561,883
5	Hydro-Conventional	489,905			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,622,444
7	Other	22,832,259			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	64,286,169	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	87,454
10	Purchases	7,424,717	27	Total Energy Losses	2,527,023
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	71,666,631
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	890,113			
17	Delivered	869,854			
18	Net Transmission for Other (Line 16 minus line 17)	20,259			
19	Transmission By Others Losses	-64,514			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	71,666,631			

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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 (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	6,436,536	301,124	13,248	19	800
30	February	5,897,749	471,074	12,457	11	800
31	March	5,318,354	761,244	9,610	3	800
32	April	5,346,905	974,818	9,031	6	800
33	May	5,733,864	921,497	9,748	26	1800
34	June	6,333,221	582,588	11,781	22	1700
35	July	7,368,498	575,402	13,061	26	1700
36	August	7,306,408	473,466	12,848	15	1700
37	September	6,164,817	546,110	11,727	8	1700
38	October	4,756,874	297,311	9,270	19	1700
39	November	5,128,054	455,572	9,907	23	800
40	December	5,875,351	262,238	12,110	16	800
41	TOTAL	71,666,631	6,622,444			

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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)	413.60			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	379			0		
7	Plant Hours Connected to Load	8662			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	87			9		
12	Net Generation, Exclusive of Plant Use - KWh	1311318000			0		
13	Cost of Plant: Land and Land Rights	4399278			0		
14	Structures and Improvements	83182135			0		
15	Equipment Costs	376004793			0		
16	Asset Retirement Costs	424475310			0		
17	Total Cost	888061516			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	2147.1507			0		
19	Production Expenses: Oper, Supv, & Engr	1187243			687		
20	Fuel	49966098			9524		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	7265713			-2		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	15151			0		
26	Misc Steam (or Nuclear) Power Expenses	1818956			52626		
27	Rents	0			0		
28	Allowances	67911			328		
29	Maintenance Supervision and Engineering	1184152			-91		
30	Maintenance of Structures	1985847			442822		
31	Maintenance of Boiler (or reactor) Plant	5425375			198		
32	Maintenance of Electric Plant	4141285			435		
33	Maintenance of Misc Steam (or Nuclear) Plant	1100614			27830		
34	Total Production Expenses	74158345			534357		
35	Expenses per Net KWh	0.0566			0.0000		
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	9504	668553	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137446	12635	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	65.860	75.760	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	82.520	71.808	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	14.294	2.842	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.037	0.037	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	12925.000	12925.000	0.000	0.000	0.000	0.000

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/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)	2484			0		
7	Plant Hours Connected to Load	7072			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	222			0		
12	Net Generation, Exclusive of Plant Use - KWh	8312055000			-345000		
13	Cost of Plant: Land and Land Rights	8105075			0		
14	Structures and Improvements	235748921			0		
15	Equipment Costs	1845043751			0		
16	Asset Retirement Costs	225067377			0		
17	Total Cost	2313965124			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	904.5286			0		
19	Production Expenses: Oper, Supv, & Engr	5149980			57479		
20	Fuel	278597763			-243327		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	11576551			695		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	65854			0		
26	Misc Steam (or Nuclear) Power Expenses	2212237			160672		
27	Rents	0			0		
28	Allowances	161895			1281		
29	Maintenance Supervision and Engineering	4687641			12745		
30	Maintenance of Structures	3209827			293520		
31	Maintenance of Boiler (or reactor) Plant	28628265			135		
32	Maintenance of Electric Plant	3927833			6853		
33	Maintenance of Misc Steam (or Nuclear) Plant	2942298			7734		
34	Total Production Expenses	341160144			297787		
35	Expenses per Net KWh	0.0410			-0.8632		
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	61985	3307654	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137905	12719	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	58.460	81.040	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	59.010	82.394	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	10.188	3.239	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.033	0.033	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10166.000	10166.000	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: *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			423.50		
6	Net Peak Demand on Plant - MW (60 minutes)	802			327		
7	Plant Hours Connected to Load	8440			1568		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	797			370		
10	When Limited by Condenser Water	741			324		
11	Average Number of Employees	777			0		
12	Net Generation, Exclusive of Plant Use - KWh	6432188000			205870000		
13	Cost of Plant: Land and Land Rights	1663503			565402		
14	Structures and Improvements	325883169			31682403		
15	Equipment Costs	923170892			63580356		
16	Asset Retirement Costs	219835396			0		
17	Total Cost	1470552960			95828161		
18	Cost per KW of Installed Capacity (line 17/5) Including	1913.2877			226.2766		
19	Production Expenses: Oper, Supv, & Engr	13829178			310832		
20	Fuel	42418524			11820152		
21	Coolants and Water (Nuclear Plants Only)	3042982			0		
22	Steam Expenses	11556948			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1873062			55248		
26	Misc Steam (or Nuclear) Power Expenses	44843889			1493860		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	15133316			143456		
30	Maintenance of Structures	5887574			153671		
31	Maintenance of Boiler (or reactor) Plant	14004278			0		
32	Maintenance of Electric Plant	9466490			791707		
33	Maintenance of Misc Steam (or Nuclear) Plant	13792010			196614		
34	Total Production Expenses	175848251			14965540		
35	Expenses per Net KWh	0.0273			0.0727		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MW Days			Barrels	MCF	
38	Quantity (Units) of Fuel Burned	820776	0	0	42138	2103908	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	137414	1026412	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	65.860	3.945	0.000
41	Average Cost of Fuel per Unit Burned	50.325	0.000	0.000	82.955	3.945	0.000
42	Average Cost of Fuel Burned per Million BTU	0.614	0.000	0.000	14.374	3.843	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.006	0.000	0.000	0.057	0.057	0.000
44	Average BTU per KWh Net Generation	10452.000	0.000	0.000	11671.000	11671.000	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	15			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		
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)	119			2494		
7	Plant Hours Connected to Load	35			7079		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	959			2143		
10	When Limited by Condenser Water	863			1868		
11	Average Number of Employees	7			71		
12	Net Generation, Exclusive of Plant Use - KWh	374000			4718460000		
13	Cost of Plant: Land and Land Rights	4581022			2839730		
14	Structures and Improvements	120921818			106715416		
15	Equipment Costs	259961196			920228291		
16	Asset Retirement Costs	0			0		
17	Total Cost	385464036			1029783437		
18	Cost per KW of Installed Capacity (line 17/5) Including	393.4511			458.7417		
19	Production Expenses: Oper, Supv, & Engr	405139			1245332		
20	Fuel	21455593			304544126		
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	201486			969649		
26	Misc Steam (or Nuclear) Power Expenses	1066146			3850310		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	359945			1928371		
30	Maintenance of Structures	77982			1323896		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	692631			11115305		
33	Maintenance of Misc Steam (or Nuclear) Plant	2696522			7692716		
34	Total Production Expenses	26955444			332669705		
35	Expenses per Net KWh	72.0734			0.0705		
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	3029	5824385	0	900	84378847	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137757	1042391	0	140000	1031703	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	122.060	3.586	0.000	71.870	3.606	0.000
41	Average Cost of Fuel per Unit Burned	162.000	3.586	0.000	98.536	3.606	0.000
42	Average Cost of Fuel Burned per Million BTU	17.997	3.440	0.000	16.770	3.495	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.038	0.038	0.000	0.029	0.029	0.000
44	Average BTU per KWh Net Generation	10964.000	10964.000	0.000	8168.000	8168.000	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			717			0			6
0			5119			0			7
0			0			0			8
0			746			0			9
0			727			0			10
0			88			0			11
0			2009522000			-1853000			12
0			14994716			0			13
0			168932483			0			14
0			1033862112			0			15
0			176983788			0			16
0			1394773099			0			17
0			1827.5329			0			18
43834			2375921			2168			19
5261			78340284			46384			20
0			0			0			21
471			4416292			0			22
0			0			0			23
0			0			0			24
0			3857			0			25
47541			2794275			217			26
0			0			0			27
607			74460			15			28
8535			948574			1120			29
347384			2623143			153844			30
3224			9457743			506			31
3932			1689074			1899			32
10987			2047319			8963			33
471776			104770942			215116			34
0.0000			0.0521			-0.1161			35
			Oil	Coal					36
			Barrels	Tons					37
0	0	0	47286	893494	0	0	0	0	38
0	0	0	137688	11926	0	0	0	0	39
0.000	0.000	0.000	59.350	78.790	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	60.266	82.987	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	10.422	3.479	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	10742.000	10742.000	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			1916			982	6
		0			8784			7961	7
		0			0			0	8
		0			1928			973	9
		0			1870			928	10
		0			1025			825	11
		0			15388724000			7513051000	12
		0			4060633			62516493	13
		0			737554838			1869653230	14
		0			2030446489			2036986111	15
		0			305308377			350994010	16
		0			3077370337			4320149844	17
		0			1536.2272			4543.2220	18
		6605			19210265			11745632	19
		15379			104019203			52874039	20
		0			10948093			6408472	21
		77			24380154			14435203	22
		0			0			0	23
		0			0			0	24
		0			2481229			1779418	25
		59114			71491650			54638704	26
		0			0			0	27
		370			0			0	28
		1372			38017255			19019144	29
		357317			7292432			12535669	30
		160			30215549			23205294	31
		15828			23798001			15545492	32
		7107			28694987			18724285	33
		463329			360548818			230911352	34
		0.0000			0.0234			0.0307	35
			Nuclear			Nuclear			36
			MW Days			MW Days			37
0	0	0	1989151	0	0	953052	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	51.540	0.000	0.000	55.179	0.000	0.000	41
0.000	0.000	0.000	0.629	0.000	0.000	0.674	0.000	0.000	42
0.000	0.000	0.000	0.007	0.000	0.000	0.007	0.000	0.000	43
0.000	0.000	0.000	10588.000	0.000	0.000	10391.000	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: *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	2010	3
1971	1968	2013	4
70.00	0.00	821.30	5
52	0	2677	6
28	0	13738	7
0	0	0	8
68	0	793	9
52	0	683	10
8	0	69	11
-73000	0	10658240000	12
0	0	1208226	13
979798	0	15577285	14
12482553	0	531032479	15
0	0	0	16
13462351	0	547817990	17
192.3193	0	667.0133	18
23260	0	1372777	19
174016	0	151614423	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
3718	0	535501	25
75013	0	2211485	26
0	0	0	27
0	0	0	28
23331	0	474701	29
29323	0	977423	30
0	0	0	31
32454	0	2194681	32
164346	0	2791013	33
525461	0	162172004	34
-7.1981	0.0000	0.0152	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Oil						Oil	Gas		36
Barrels						Barrels	MCF		37
1637	0	0	0	0	0	1049	32175032	0	38
140492	0	0	0	0	0	139964	1031468	0	39
58.470	0.000	0.000	0.000	0.000	0.000	65.260	4.704	0.000	40
102.896	0.000	0.000	0.000	0.000	0.000	121.606	4.704	0.000	41
17.442	0.000	0.000	0.000	0.000	0.000	20.390	4.561	0.000	42
-2.307	0.000	0.000	0.000	0.000	0.000	0.032	0.032	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	7034.000	7034.000	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: *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
1045.80			1174.00			163.00			5
240			986			637			6
1186			7955			1885			7
0			0			0			8
911			1047			164			9
735			910			128			10
0			73			5			11
114391000			6402250000			556236000			12
42258			673304			84323			13
8530273			23100854			3462578			14
132497724			666543106			19703569			15
0			0			0			16
141070255			690317264			23250470			17
134.8922			588.0045			142.6409			18
350218			697303			54238			19
9123857			186580498			540752			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
374067			949393			9010			25
1667075			2585255			201415			26
0			0			0			27
0			0			0			28
256062			1054682			42833			29
218364			4697765			292229			30
0			0			0			31
1282216			14193296			370415			32
407419			1331175			174295			33
13679278			212089367			1685187			34
0.1196			0.0331			0.0030			35
Oil	Gas		Oil	Gas		Oil			36
Barrels	MCF		Barrels	MCF		Barrels			37
35577	1309887	0	3687	44745285	0	5437	0	0	38
137642	1030313	0	138363	1038316	0	139977	0	0	39
55.920	3.957	0.000	122.060	4.163	0.000	60.330	0.000	0.000	40
108.860	3.957	0.000	56.575	4.163	0.000	92.216	0.000	0.000	41
18.831	3.840	0.000	17.918	4.010	0.000	15.687	0.000	0.000	42
0.079	0.079	0.000	0.029	0.029	0.000	1.341	0.000	0.000	43
13596.000	13596.000	0.000	7259.000	7259.000	0.000	85461.000	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: (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
									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

Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.
Account 501016 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant $3,294,460.

Schedule Page: 402 Line No.: 20 Column: c

Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: d

Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: e

Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.
Account 501016 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant $3,294,460.

Schedule Page: 403 Line No.: 20 Column: f

Total fuel costs reflect Fuel Handling.

Schedule Page: 402 Line No.: 22 Column: b

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

Schedule Page: 402 Line No.: 22 Column: c

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

Schedule Page: 403 Line No.: 22 Column: d

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

Schedule Page: 403 Line No.: 22 Column: e

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

Schedule Page: 403 Line No.: 22 Column: f

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

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: 403.1 Line No.: 14 Column: f

Capital building leased from North City Associates and Company C/O QT Management LLC with remaining balance of $1,920,005

Schedule Page: 402.1 Line No.: 20 Column: b

Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.
Account 501016 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant $3,294,460.

Schedule Page: 402.1 Line No.: 20 Column: c

Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403.1 Line No.: 20 Column: d

Total fuel costs include Fuel Handling and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 22 Column: b

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

Schedule Page: 402.1 Line No.: 22 Column: c

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

Schedule Page: 403.1 Line No.: 22 Column: d

Account 502160 and 502161 for Fuel Synergies is excluded as it reflects merger savings not allocated by plant.

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: 402.2 Line No.: 20 Column: c

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

Schedule Page: 403.2 Line No.: 20 Column: d

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

Schedule Page: 403.2 Line No.: 20 Column: f

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

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: 403.3 Line No.: 14 Column: e

HF Lee and Wayne County capital pipelines leased from Piedmont Natural Gas with remaining lease balance of $110,728,879 as of 12/31/2016. Piedmont Natural Gas merged with Duke Energy in 2016.

Schedule Page: 403.3 Line No.: 20 Column: d

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

Schedule Page: 403.3 Line No.: 20 Column: e

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

Schedule Page: 403.3 Line No.: 20 Column: f

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

Schedule Page: 402.4 Line No.: 14 Column: b

HF Lee and Wayne County capital pipelines leased from Piedmont Natural Gas with remaining lease balance of $110,728,879 as of 12/31/2016. Piedmont Natural Gas merged with Duke Energy in 2016.

Schedule Page: 402.4 Line No.: 20 Column: b

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

Schedule Page: 402.4 Line No.: 20 Column: c

Accounts 547123 and 547127 for Fuel Synergies are excluded as they reflect merger savings not allocated by plant ($5,863,197).

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	04/13/2017	End of 2016/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 (b)	FERC Licensed Project No. 0 Plant Name: Tillery (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)	26	85
7	Plant Hours Connect to Load	8,326	3,387
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	8	6
12	Net Generation, Exclusive of Plant Use - Kwh	72,415,000	152,384,010
13	Cost of Plant		
14	Land and Land Rights	500,333	1,151,690
15	Structures and Improvements	4,183,330	2,587,757
16	Reservoirs, Dams, and Waterways	8,275,324	6,859,609
17	Equipment Costs	15,721,860	17,838,043
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	235,619	206,802
20	TOTAL cost (Total of 14 thru 19)	28,916,466	28,643,901
21	Cost per KW of Installed Capacity (line 20 / 5)	1,175.4661	340.9988
22	Production Expenses		
23	Operation Supervision and Engineering	262,136	614,536
24	Water for Power	22,234	40,266
25	Hydraulic Expenses	134,407	-362,425
26	Electric Expenses	14,955	47,433
27	Misc Hydraulic Power Generation Expenses	205,701	291,552
28	Rents	0	0
29	Maintenance Supervision and Engineering	31,907	80,708
30	Maintenance of Structures	221,835	74,197
31	Maintenance of Reservoirs, Dams, and Waterways	216,113	612,404
32	Maintenance of Electric Plant	101,098	104,861
33	Maintenance of Misc Hydraulic Plant	834,698	772,620
34	Total Production Expenses (total 23 thru 33)	2,045,084	2,276,152
35	Expenses per net KWh	0.0282	0.0149

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	04/13/2017	End of 2016/Q4

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 (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
115	0	0	6
8,749	0	0	7
			8
113	0	0	9
113	0	0	10
7	0	0	11
256,429,000	0	0	12
			13
712,606	0	0	14
3,278,016	0	0	15
29,533,146	0	0	16
19,409,269	0	0	17
8,258	0	0	18
94,496	0	0	19
53,035,791	0	0	20
491.0721	0.0000	0.0000	21
			22
899,477	0	0	23
0	0	0	24
3,930	0	0	25
27,436	0	0	26
290,319	0	0	27
0	0	0	28
101,729	0	0	29
33,760	0	0	30
546,374	0	0	31
220,118	0	0	32
598,007	0	0	33
2,721,150	0	0	34
0.0106	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	04/13/2017	End of 2016/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	04/13/2017	End of 2016/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.
			1
			2
			3
			4
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			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	04/13/2017	End of 2016/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	7.0	8,677,000	13,044,833
2	FERC Licensed Project No. 2380					
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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) 04/13/2017	Year/Period of Report End of 2016/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.
2,608,967	39,989		130,537			1
						2
						3
						4
						5
						6
						7
						8
						9
						10
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						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	04/13/2017	End of 2016/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	45.10		1
5	Mayo	Person	500.00	500.00	T	9.94		1
6	Richmond	Newport (Duke)	500.00	500.00	T	32.69		1
7	Wake	Carson (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	7.00		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	6.66		2
17	Asheville Plant	Enka	230.00	230.00	S-SP	0.43		1
18	Asheville Plant	Pisgah Forest (DPC)	230.00	230.00	DC-T	0.18		2
19	Asheville Plant	Pisgah Forest (DPC)	230.00	230.00	W-H Fr.	3.43		1
20	Asheville Plant	Pisgah Forest (DPC)	230.00	230.00	W-H Fr.	3.43	0.18	1
21	Aurora	Aurora PCS (Black)	230.00	230.00	DC-CP	0.74		2
22	Aurora	Aurora PCS (Black)	230.00	230.00	W-H Fr.	1.44		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.	1.46	0.74	1
28	Aurora	Greenville	230.00	230.00	DC-T	1.87		2
29	Aurora	Greenville	230.00	230.00	W-H Fr.	36.77		1
30	Aurora	New Bern	230.00	230.00	W-H Fr.	27.74		1
31	Biscoe	Rockingham	230.00	230.00	S-HFR	0.18		1
32	Biscoe	Rockingham	230.00	230.00	W-HFR	36.83		1
33	Brunswick Plant	Castle Hayne (East)	230.00	230.00	S-HFR	1.21		1
34	Brunswick Plant	Castle Hayne (East)	230.00	230.00	DC-T	1.15		2
35	Brunswick Plant	Castle Hayne (East)	230.00	230.00	W-H Fr.	24.43		1
36					TOTAL	6,139.69	141.10	635

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	04/13/2017	End of 2016/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	Brunswick Plant	Castle Hayne (East)	230.00	230.00	S-SP	7.21		1
2	Brunswick Plant	Castle Hayne (East)	230.00	230.00	C-SP	0.70		1
3	Brunswick Plant	Delco (East)	230.00	230.00	DC-T	0.17		2
4	Brunswick Plant	Delco (East)	230.00	230.00	W-H Fr.	29.85		1
5	Brunswick Plant	Delco (East)	230.00	230.00	S-HFR	1.13		1
6	Brunswick Plant	Jacksonville	230.00	230.00	W-H Fr.	75.21		1
7	Brunswick Plant	Weatherspoon Plant	230.00	230.00	DC-T	0.28		2
8	Brunswick Plant	Weatherspoon Plant	230.00	230.00	W-H Fr.	77.65		1
9	Brunswick Plant	Wilmington Corning SW Sta	230.00	230.00	S-SP	7.04		1
10	Brunswick Plant	Wilmington Corning SW Sta	230.00	230.00	W-H Fr.	17.13	1.15	1
11	Brunswick Plant	Wilmington Corning SW Sta	230.00	230.00	S-H Fr.	1.36		1
12	Brunswick Plant	Delco (West)	230.00	230.00	W-H Fr.	30.35		1
13	Brunswick Plant	Delco (West)	230.00	230.00	S-H Fr.	1.08		1
14	Brunswick Plant	Wallace	230.00	230.00	W-H Fr.	53.57		1
15	Brunswick Plant	Wallace	230.00	230.00	S-H Fr.	1.25		1
16	Brunswick Plant	Whiteville	230.00	230.00	W-H Fr.	47.74		1
17	Brunswick Plant	Whiteville	230.00	230.00	S-H Fr.	1.07		1
18	Brunswick Plant Unit #1	Brunswick Plant U#1 CAP	230.00	230.00	S-HFR	0.20		1
19	Cane River	Nagel East & West(APCO)	230.00	230.00	DC-T	15.01		2
20	Cane River	Craggy	230.00	230.00	S-H Fr.	26.39		1
21	Cape Fear Plant	Harris Plant (North)	230.00	230.00	W-H Fr.	7.12		1
22	Cape Fear Plant	Harris Plant (North)	230.00	230.00	S-H Fr.	0.25		1
23	Cape Fear Plant	Harris Plant (South)	230.00	230.00	W-H Fr.	6.14		1
24	Cape Fear Plant	Harris Plant (South)	230.00	230.00	S-H Fr.	0.38		1
25	Cape Fear Plant	Jonesboro	230.00	230.00	W-H Fr.	10.10		1
26	Cape Fear Plant	West End	230.00	230.00	W-H Fr.	37.54		1
27	Cary Regency Park	Method	230.00	230.00	DC-SSP	0.22		2
28	Cary Regency Park	Method	230.00	230.00	S-SP	4.53		1
29	Cary Regency Park	Method	230.00	230.00	W-H Fr.	3.99		1
30	Cary Regency Park	RTP	230.00	230.00	S-HFR	11.03		1
31	Castle Hayne	Jacksonville	230.00	230.00	W-H Fr.	44.90		1
32	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	S-SP	0.45		1
33	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	W-HFR	5.12		1
34	Clinton	Erwin	230.00	230.00	S-SP	3.89		1
35	Clinton	Erwin	230.00	230.00	W-H Fr.	30.43		1
36					TOTAL	6,139.69	141.10	635

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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 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	Clinton	Mt Olive	230.00	230.00	S-HFR	0.27		1
2	Clinton	Mt. Olive	230.00	230.00	S-SP	14.22		1
3	Clinton	Wallace	230.00	230.00	W-H Fr.	36.68		1
4	Cumberland	Delco	230.00	230.00	W-H Fr.	54.40		1
5	Cumberland	Fayetteville (North)	230.00	230.00	DC-SSP	5.16		2
6	Cumberland	Fayetteville (North)	230.00	230.00	W-H Fr.	8.58		1
7	Cumberland	Fayetteville (South)	230.00	230.00	W-H Fr.	13.73		1
8	Cumberland	Whiteville	230.00	230.00	W-H Fr.	40.93		1
9	Durham	East Durham (DPC)	230.00	230.00	DC-SH Fr.	0.75		2
10	Durham	East Durham (DPC)	230.00	230.00	C-H Fr.	0.60		1
11	Durham	East Durham (DPC)	230.00	230.00	W-H Fr.	8.31		1
12	Durham	Falls	230.00	230.00	S-HFR	3.53		1
13	Durham	Falls	230.00	230.00	DC S-HFR	9.14		2
14	Durham	Falls	230.00	230.00	S-SP	1.15		1
15	Durham	Method	230.00	230.00	DC-SSP	1.52		2
16	Durham	Method	230.00	230.00	S-SP	13.53		1
17	Durham	Method	230.00	230.00	W-H Fr.	1.15		1
18	Durham	RTP	230.00	230.00	s-hfr	10.10		1
19	Erwin	Fayetteville East	230.00	230.00	W-H Fr.	23.09		1
20	Erwin	Milburnie	230.00	230.00	S-HFR	0.50		1
21	Erwin	Milburnie	230.00	230.00	S-SP	0.71		1
22	Erwin	Milburnie	230.00	230.00	DC-T	1.83		2
23	Erwin	Milburnie	230.00	230.00	W-H Fr.	34.08		1
24	Erwin	Selma	230.00	230.00	S-SP	3.14		1
25	Erwin	Selma	230.00	230.00	W-H Fr.	22.06		1
26	Falls	Milburnie	230.00	230.00	DC-T	10.92		2
27	Falls	Milburnie	230.00	230.00	S-H Fr.	0.32		1
28	Fayetteville	Fayetteville East	230.00	230.00	DC-T	0.97		2
29	Fayetteville	Fayetteville East	230.00	230.00	W-H Fr.	9.82		1
30	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	DC-SSP	0.21		2
31	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	S-SP	6.99		1
32	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	W-H Fr.	13.68		1
33	Fayetteville	Raeford	230.00	230.00	DC-SSP	2.15		2
34	Fayetteville	Raeford	230.00	230.00	W-H Fr.	14.79		1
35	Fayetteville	Rockingham	230.00	230.00	W-H Fr.	50.92	1.88	1
36					TOTAL	6,139.69	141.10	635

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	Fayetteville	Rockingham	230.00	230.00	DC S-HFR	2.63		2
2	Fayetteville	Rockingham			(W-HFR)	-2.30		-1
3	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC-SH Fr.	6.44		2
4	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.73	0.21	1
5	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.03		2
6	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	S-SP	5.98		1
7	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	DC S-HFR	2.77		2
8	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	S-SP	3.70		1
9	Fort Bragg Woodruff St.	Richmond Sub	230.00	230.00	S-HFR	51.32		1
10	Greenville	Everetts (VP)	230.00	230.00	DC-T	0.61		1
11	Greenville	Wilson	230.00	230.00	W-H Fr.	14.56		1
12	Greenville	Wilson	230.00	230.00	DC-T	0.65		1
13	Harris Plant	Siler City	230.00	230.00	S-H Fr.	10.79		1
14	Harris Plant	Siler City	230.00	230.00	W-H Fr.	20.69		1
15	Harris Plant	Apex US #1	230.00	230.00	W-H Fr.	3.96		1
16	Harris Plant	Erwin	230.00	230.00	S-H Fr.	0.92		1
17	Harris Plant	Erwin	230.00	230.00	W-H Fr.	28.85		1
18	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	DC-SSP	1.15		2
19	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	S-H Fr.	0.27		1
20	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	W-H Fr.	34.23		1
21	Harris Plant	RTP	230.00	230.00	S-SP	2.87		1
22	Harris Plant	Wake	230.00	230.00	S-SP	5.39		1
23	Harris Plant	Wake	230.00	230.00	S-H Fr.	32.39		1
24	Havelock	Jacksonville	230.00	230.00	DC-T	10.41		2
25	Havelock	Jacksonville	230.00	230.00	W-H Fr.	27.84		1
26	Havelock	Morehead Wildwood	230.00	230.00	DC-SSP	0.27		2
27	Havelock	Morehead Wildwood	230.00	230.00	W-H Fr.	14.82		1
28	Havelock	Morehead Wildwood	230.00	230.00	S-SP	0.23		1
29	Havelock	New Bern	230.00	230.00	DC-T	0.13		2
30	Havelock	New Bern	230.00	230.00	W-H Fr.	23.34		1
31	Havelock Sub	Havelock Cap Bank	230.00	230.00	S-HFR	0.07		1
32	Henderson	Person	230.00	230.00	DC-T	2.46		2
33	Henderson	Person	230.00	230.00	W-H Fr.	37.47		1
34	Jacksonville	Jacksonville Svc	230.00	230.00	S-HFR	0.10		1
35	Jacksonville	New Bern	230.00	230.00	W-H Fr.	30.16		1
36					TOTAL	6,139.69	141.10	635

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	04/13/2017	End of 2016/Q4

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Jacksonville	Wallace	230.00	230.00	W-H Fr.	30.82		1
2	Kinston DuPont	Wommack	230.00	230.00	S-SP	0.14		1
3	Kinston DuPont	Wommack	230.00	230.00	W-H Fr.	2.21		1
4	Kinston DuPont	Wommack	230.00	230.00	S-HFR	16.85		1
5	Laurinburg	Richmond	230.00	230.00	C-SP	3.32		1
6	Laurinburg	Richmond	230.00	230.00	W-H Fr.	17.12		1
7	Lee Sub	Milburnie	230.00	230.00	S-SP	0.43		1
8	Lee Sub	Milburnie	230.00	230.00	W-H Fr.	40.30	1.36	1
9	Lee Sub	Mt. Olive	230.00	230.00	S-HFR	0.23		1
10	Lee Sub	Mt. Olive	230.00	230.00	S-SP	10.39		1
11	Lee Sub	Mt. Olive	230.00	230.00	DC S-HFR	3.21		2
12	Lee Sub	Selma	230.00	230.00	S-SP	0.24		1
13	Lee Sub	Selma	230.00	230.00	W-H Fr.	16.54		1
14	Lee Sub	Wommack (North)	230.00	230.00	W-H Fr.	30.47		1
15	Lee Sub	Wommack (South)	230.00	230.00	S-HFR	29.45		1
16	Lilesville	DPC Oakboro (Black)	230.00	230.00	S-HFR	24.70		1
17	Lilesville	DPC Oakboro (White)	230.00	230.00	S-HFR	24.70		1
18	LIlesville	Rockingham (Black)	230.00	230.00	S-HFR	10.36		1
19	Lilesville	Rockingham (White)	230.00	230.00	S-HFR	10.35		1
20	Lilesville SW	Rockingham	230.00	230.00	S-HFR	12.70		1
21	MARION	WHITEVILLE	230.00	230.00	S-SP	21.91		1
22	Method	East Durham (DPC)	230.00	230.00	DC-SH Fr.	0.77		2
23	Method	East Durham (DPC)	230.00	230.00	S-SP	4.36		1
24	Method	East Durham (DPC)	230.00	230.00	C-H Fr.	0.55		1
25	Method	East Durham (DPC)	230.00	230.00	W-H Fr.	12.86	1.53	1
26	Method	East Durham (DPC)	230.00	230.00	S-H Fr.	2.16		1
27	Method	Milburnie	230.00	230.00	DC-SSP	4.10		2
28	Method	Milburnie	230.00	230.00	S-SP	3.79		1
29	Method	Milburnie	230.00	230.00	W-SP	4.59	0.26	1
30	Milburnie	Person	230.00	230.00	DC-T	36.82		2
31	Milburnie	Person	230.00	230.00	S-H Fr.	12.18		1
32	Milburnie	Person	230.00	230.00	W-H Fr.	0.49	10.92	1
33	Milburnie	Wake	230.00	230.00	W-H Fr.	7.00		1
34	New Bern	Wommack (North)	230.00	230.00	S-H Fr.	3.11		1
35	New Bern	Wommack (North)	230.00	230.00	S-SP	0.14		1
36					TOTAL	6,139.69	141.10	635

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	New Bern	Wommack (North)	230.00	230.00	W-H Fr.	28.78		1
2	New Bern	Wommack (South)	230.00	230.00	W-HFR	33.87		1
3	Person	Rocky Mount	230.00	230.00	S-HFR	2.60		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	Halifax (VP)	230.00	230.00	W-H Fr.	4.85		1
8	Raeford	Richmond	230.00	230.00	W-H Fr.	35.17		1
9	Richmond	Rockingham	230.00	230.00	S-HFR	0.40		1
10	Richmond	Rockingham	230.00	230.00	W-H Fr.	5.57		1
11	Richmond	Rockingham	230.00	230.00	DCS C-SP	1.41		1
12	Richmond	Rockingham	230.00	230.00	S-HFR	6.40		1
13	Richmond County Plant	Richmond Substation (Black)	230.00	230.00	S-HFR	1.09		1
14	Richmond County Plant	Richmond Substation (White)	230.00	230.00	S-HFR	0.88		1
15	Richmond County Plant	Richmond 500kV Sub	230.00	230.00	S-HFR	1.56		1
16	Rockingham	Oakboro (DPC) B&W	230.00	230.00	DC-T	34.83		2
17	Rockingham	West End	230.00	230.00	DC-T	5.75		2
18	Rockingham	West End	230.00	230.00	W-H Fr.	28.24		1
19	Rockingham	West End	230.00	230.00	DC S-HFR	2.30		2
20	Rockingham	West End	230.00	230.00	S-HFR	29.81		1
21	Rocky Mount	Edgecombe (VP)	230.00	230.00	DC-T	4.25		2
22	Rocky Mount	Edgecombe (VP)	230.00	230.00	DC-SSP	0.30		2
23	Rocky Mount	Hornertown (VP)	230.00	230.00	T		4.55	2
24	Rocky Mount	Wilson	230.00	230.00	S-SP	0.85		1
25	Rocky Mount	Wilson	230.00	230.00	DC-SSP	8.26		2
26	Rocky Mount	Wilson	230.00	230.00	DC S-HFR	3.68		2
27	Roxboro Plant	East Danville (AEP) (North)	230.00	230.00	S-HFR	1.79		1
28	Roxboro Plant	East Danville (AEP) (North)	230.00	230.00	DC S-HFR	7.26		2
29	Roxboro Plant	East Danville (AEP) (North)	230.00	230.00	DC S-SP	1.74		2
30	Roxboro Plant	East Danville (AEP) (South)	230.00	230.00	S-HFR	1.82		1
31	Roxboro Plant	East Danville (AEP) (South)	230.00	230.00	DC S-HFR	7.26		2
32	Roxboro Plant	East Danville (AEP) (South)	230.00	230.00	DC S-SP	1.74		2
33	Roxboro Plant	Falls	230.00	230.00	DC-T	0.15		2
34	Roxboro Plant	Falls	230.00	230.00	C-SP	0.21		1
35	Roxboro Plant	Falls	230.00	230.00	S-H Fr.	0.17		1
36					TOTAL	6,139.69	141.10	635

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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	Roxboro Plant	Falls	230.00	230.00	W-H Fr.	1.55	47.74	1
2	Roxboro Plant	East Durham (East) (DPC)	230.00	230.00	C-H Fr.	1.65		1
3	Roxboro Plant	East Durham (East) (DPC)	230.00	230.00	W-H Fr.	31.99	0.76	1
4	Roxboro Plant	East Durham (West) (DPC)	230.00	230.00	C-H Fr.	1.71		1
5	Roxboro Plant	East Durham (West) (DPC)	230.00	230.00	W-H Fr.	31.98	0.77	1
6	Roxboro Plant	Eno (DPC) B&W	230.00	230.00	DC-T	33.78		2
7	Roxboro Plant	Person (Middle)	230.00	230.00	T	0.14		1
8	Roxboro Plant	Person (Middle)	230.00	230.00	C-H Fr.	0.10		1
9	Roxboro Plant	Person (Middle)	230.00	230.00	S-H Fr.	1.83		1
10	Roxboro Plant	Person (CEFFO)	230.00	230.00	C-SP	0.21		1
11	Roxboro Plant	Person (CEFFO)	230.00	230.00	W-H Fr.	1.90	0.15	1
12	Roxboro Plant	Person (HYCO)	230.00	230.00	T	0.08		1
13	Roxboro Plant	Person (HYCO)	230.00	230.00	W-H Fr.	1.18		1
14	RTP	Amberly	230.00	230.00	S-SP	4.11		2
15	RTP	Green Level	230.00	230.00	S-SP	6.53		1
16	Selma	Wake	230.00	230.00	W-H Fr.	21.00		1
17	Sutton Plant	Castle Hayne	230.00	230.00	W-H Fr.	13.93		1
18	Sutton Plant	Delco	230.00	230.00	W-H Fr.	14.90	0.28	1
19	Sutton Plant	Delco	230.00	230.00	S-HFR	0.44		1
20	Sutton Plant	Delco			(W-HFR)	-0.34		1
21	Sutton Plant	Wallace	230.00	230.00	T	3.21		1
22	Sutton Plant	Wallace	230.00	230.00	W-H Fr.	29.13		1
23	Wake	Zebulon	230.00	230.00	W-H Fr.	10.74		1
24	Wake	Zebulon	230.00	230.00	S-H Fr.	0.49		1
25	Weatherspoon Plant	Fayetteville	230.00	230.00	W-H Fr.	32.55	0.97	1
26	Weatherspoon Plant	Latta	230.00	230.00	T	0.37		1
27	Weatherspoon Plant	Latta	230.00	230.00	W-H Fr.	18.29	0.28	1
28	Weatherspoon Plant	Laurinburg	230.00	230.00	W-H Fr.	31.46		1
29	Weatherspoon Plant	Laurinburg	230.00	230.00	S-H Fr.	0.99		1
30	Wayne County Plant	Lee Substation	230.00	230.00	S-HFR	0.31		1
31	Wilmington Corning SW Sta.	Wilmington Corning Sub. (N)	230.00	230.00	S-SP	0.48		1
32	Wilmington Corning SW Sta.	Wilmington Corning Sub (S)	230.00	230.00	S-SP	0.43		1
33	Wilson	Zebulon	230.00	230.00	W-H Fr.	25.92		1
34	Wilson	Zebulon	230.00	230.00	S-H Fr.	0.46		1
35	Tap Point	Angier	230.00	230.00	W-H Fr.	0.11		1
36					TOTAL	6,139.69	141.10	635

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	04/13/2017	End of 2016/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 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	Ansonville	230.00	230.00	S-SP	0.03		1
2	Tap Point	Apex (Bank #1)	230.00	230.00	W-H Fr.	0.01		1
3	Tap Point	Apex (Bank #2)	230.00	230.00	S-HFR	0.01		1
4	Tap Point	Apex (Bank #3)	230.00	230.00	S-HFR	0.03		1
5	Tap Point	Auburn	230.00	230.00	W-H Fr.	0.10		1
6	Tap Point	Bahama	230.00	230.00	W-H Fr.	0.06		1
7	Tap Point	Bailey	230.00	230.00	W-H Fr.	1.38		1
8	Tap Point	Bayboro	230.00	230.00	W-H Fr.	2.13		1
9	Tap Point	Benson	230.00	230.00	W-H Fr.	0.01		1
10	Tap Point	Benson PGI	230.00	230.00	W-H Fr.	1.98		1
11	Tap Point	Buies Creek	230.00	230.00	W-H Fr.	0.06		1
12	Tap Point	Bynum	230.00	230.00	S-HFR	0.06		1
13	Tap Point	Bynum	230.00	230.00	W-H Fr.	9.26		1
14	Tap Point	Camden 230/23kV Yard	230.00	230.00	W-HFR	0.18		1
15	Tap Point	Camp LeJeune #1	230.00	230.00	W-H Fr.	4.65		1
16	Tap Point	Camp LeJeune #2	230.00	230.00	W-H Fr.	0.04		1
17	Tap Point	Camp LeJeune French Creek	230.00	230.00	S-SP/S-HFR	2.92		1
18	Tap Point	Cary	230.00	230.00	W-H Fr.	0.93		1
19	Tap Point	Cary Evans Road (East)	230.00	230.00	W-H Fr.	0.04		1
20	Tap Point	Cary Evans Road (West)	230.00	230.00	S-HFR	0.04		1
21	Tap Point	Cary Trenton Road	230.00	230.00	S-SP-11	4.34		1
22	Tap Point	Cary Triangle Forest	230.00	230.00	W-H Fr.	0.04		1
23	Tap Point	Catherine Lake	230.00	230.00	W-H Fr.	0.08		1
24	Tap Point	Chocowinity	230.00	230.00	W-H Fr.	0.05		1
25	Tap Point	Clifdale	230.00	230.00	W-H Fr.	0.54		1
26	Tap Point	Concord	230.00	230.00	S-HFR	0.13		1
27	Tap Point	Craven County Wood Energy	230.00	230.00	W-H Fr.	1.87		1
28	Tap Point	Dover	230.00	230.00	S-HFR	0.04		1
29	Tap Point	Dudley Georgia Pacific	230.00	230.00	W-H Fr.	2.64		1
30	Tap Point	Ellerbe	230.00	230.00	W-H Fr.	0.04		1
31	Tap Point	Fort Bragg Knox St.	230.00	230.00	W-H Fr.	0.08		1
32	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	S-SP	0.47		1
33	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	DC S-HFR	2.75		2
34	Tap Point	Fort Bragg Main	230.00	230.00	S-SP	0.04		1
35	Tap Point	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.07		1
36					TOTAL	6,139.69	141.10	635

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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	Four Oaks	230.00	230.00	W-H Fr.	0.07		1
2	Tap Point	Fuquay	230.00	230.00	W-H Fr.	0.48		1
3	Tap Point	Fuquay Bells Lake	230.00	230.00	W-H Fr.	0.15		1
4	Tap Point	Garland	230.00	230.00	W-H Fr.	0.06		1
5	Tap Point	Garner Panther Branch	230.00	230.00	W-H Fr.	0.15		1
6	Tap Point	Camp Geiger	230.00	230.00	S-SP	1.94		1
7	Tap Point	Grantham	230.00	230.00	W-H Fr.	0.10		1
8	Tap Point	Hamlet	230.00	230.00	W-H Fr.	0.02		1
9	Tap Point	Hamlet	230.00	230.00	S-HFR	0.02		1
10	Tap Point	Henderson East	230.00	230.00	W-H Fr.	0.06		1
11	Tap Point	Holly Springs (East)	230.00	230.00	S-HFR	0.11		1
12	Tap Point	Holly Springs (West)	230.00	230.00	S-HFR	0.11		1
13	Tap Point	Holly Springs Industrial	230.00	230.00	S-HFR	0.83		1
14	Tap Point	Hope Mills Rockfish Road	230.00	230.00	W-H Fr.	0.07		1
15	Tap Point	Jacksonville Tarawa	230.00	230.00	W-H Fr.	0.04		1
16	Tap Point	Knightdale Square D	230.00	230.00	W-H Fr.	0.95		1
17	Tap Point	Laurel Hills	230.00	230.00	W-H Fr.	0.03		1
18	Tap Point	Laurinburg City	230.00	230.00	W-H Fr.	0.03		1
19	Tap Point	Leesville Wood Valley	230.00	230.00	W-H Fr.	0.15		1
20	Tap Point	Lumberton POD#3	230.00	230.00	S-SP	0.70		1
21	Tap Point	Masonboro	230.00	230.00	S-SP	0.03		1
22	Tap Point	Mayo Plant	230.00	230.00	W-H Fr.	3.06		1
23	Tap Point	Morrisville	230.00	230.00	W-H Fr.	0.11		1
24	Tap Point	NCSU CBC	230.00	230.00	S-HFR	0.20		1
25	Tap Point	New Bern West	230.00	230.00	W-H Fr.	0.04		1
26	Tap Point	New Hill	230.00	230.00	W-H Fr.	0.20		1
27	Tap Point	Newton Grove	230.00	230.00	W-H Fr.	2.13		1
28	Tap Point	Oxford North	230.00	230.00	W-H Fr.	0.92		1
29	Tap Point	Oxford South	230.00	230.00	W-H Fr.	6.30		1
30	Tap Point	Person Sub 230/24kV Bank	230.00	230.00	S-HFR	0.11		1
31	Tap Point	Pitt Greene EMC	230.00	230.00	S-HFR	0.04		1
32	Tap Point	Pittsboro	230.00	230.00	W-H Fr.	0.03		1
33	Tap Point	Prospect	230.00	230.00	W-H Fr.	0.03		1
34	Tap Point	Raleigh Blue Ridge Road	230.00	230.00	S-SP	0.03		1
35	Tap Point	Raleigh Durham Airport	230.00	230.00	W-H Fr.	0.09		1
36					TOTAL	6,139.69	141.10	635

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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	Raleigh Foxcroft	230.00	230.00	W-H Fr.	0.03		1
2	Tap Point	Raleigh Homestead (North)	230.00	230.00	S-HFR	0.07		1
3	Tap Point	Raleigh Homestead (South)	230.00	230.00	S-HFR	0.07		1
4	Tap Point	Raleigh Honeycutt	230.00	230.00	S-SP	2.08		1
5	Tap Point	Raleigh Leesville Road	230.00	230.00	W-H Fr.	0.04		1
6	Tap Point	Raleigh NCSU Centennial	230.00	230.00	S-SP	0.05		1
7	Tap Point	Raleigh Oakdale	230.00	230.00	S-SP	1.26		1
8	Tap Point	Raleigh Six Forks	230.00	230.00	S-H Fr.	0.07		1
9	Tap Point	Rockingham Aberdeen Road	230.00	230.00	W-H Fr.	0.60		1
10	Tap Point	Rolesville	230.00	230.00	W-H Fr.	5.67		1
11	Tap Point	Rose Hill	230.00	230.00	W-H Fr.	0.16		1
12	Tap Point	Rowland	230.00	230.00	W-H Fr.	6.86		1
13	Tap Point	Roxboro Bowmantown Road	230.00	230.00	S-HFR	0.04		1
14	Tap Point	Roxboro Cogentrix	230.00	230.00	W-H Fr.	0.60		1
15	Tap Point	Roxb. Plt Unit #3 C. Tower	230.00	230.00	W-H Fr.	0.24		1
16	Tap Point	Roxboro South	230.00	230.00	W-H Fr.	0.79		1
17	Tap Point	Sanford Deep River	230.00	230.00	W-H Fr.	2.63		1
18	Tap Point	Sanford Deep River	230.00	230.00	S-HFR	0.09		1
19	Tap Point	Sanford Garden Street	230.00	230.00	W-H Fr.	3.25		1
20	Tap Point	Sanford Horner Blvd.	230.00	230.00	W-H Fr.	0.04		1
21	Tap Point	Scotts Hill	230.00	230.00	S-SP	3.37		1
22	Tap Point	Siler City Hwy. 64	230.00	230.00	S-HFR	0.53		1
23	Tap Point	Southport	230.00	230.00	W-H Fr.	1.88		1
24	Tap Point	Southport Adm (West)	230.00	230.00	W-H Fr.	0.48		1
25	Tap Point	Southport Cogentrix	230.00	230.00	W-H Fr.	0.30		1
26	Tap Point	Summerton	230.00	230.00	W-H Fr.	2.70		1
27	Tap Point	Swansbsoro	230.00	230.00	W-H Fr.	0.07		1
28	Tap Point	Tideland EMC Edwards	230.00	230.00	S-SP	0.61		1
29	Tap Point	Topsail	230.00	230.00	W-H Fr.	1.55		1
30	Tap Point	Town of Apex POD #4	230.00	230.00	S-HFR	0.12		1
31	Tap Point	Town of Farmville	230.00	230.00	S-HFR	0.03		1
32	Tap Point	Wadesboro Bowman School	230.00	230.00	S-HFR	12.98		8
33	Tap Point	Wake Tech	230.00	230.00	S-HFR	0.06		1
34	Tap Point	Warsaw	230.00	230.00	S-SP	0.61		1
35	Tap Point	Warsaw	230.00	230.00	W-H Fr.	2.46		1
36					TOTAL	6,139.69	141.10	635

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	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	Weatherspoon Sub	230.00	230.00	W-H Fr.	0.09		1
2	Tap Point	Wendell	230.00	230.00	W-H Fr.	0.07		1
3	Tap Point	Wilmington Kosa	230.00	230.00	W-H Fr.	0.58		1
4	Tap Point	Wilmington Cedar Avenue	230.00	230.00	S-SP	0.21		1
5	Tap Point	Wilmington East	230.00	230.00	W-H Fr.	0.01		1
6	Tap Point	Wilmington Ninth & Orange	230.00	230.00	S-SP	2.01		1
7	Tap Point	Wilmington Ogden (East)	230.00	230.00	W-H Fr.	0.06		1
8	Tap Point	Wilmington Ogden (West)	230.00	230.00	S-HFR	0.06		1
9	Tap Point	Wilmington Praxair	230.00	230.00	W-H Fr.	0.58		1
10	Tap Point	Wilmington Basf	230.00	230.00	W-H Fr.	0.22		1
11	Tap Point	Wilson Mills	230.00	230.00	W-H Fr.	0.09		1
12	Tap Point	Yanceyville	230.00	230.00	S-SP	10.36		1
13	Barnard Creek	Town Creek	230.00	230.00	Underground	1.42		1
14	Camden	Lugoff(SCPSA)	230.00	230.00	W-H Fr.	5.37		1
15	Darlington County Plant	Florence	230.00	230.00	S-SP	37.28		1
16	Darlington County Plant	Robinson Plant (South)	230.00	230.00	W-H Fr.	1.71		1
17	Darlington County Plant	Robinson Plant (North)	230.00	230.00	S-HFR	1.67		1
18	Darlington County Plant	South Bethune (SCPSA)	230.00	230.00	W-H Fr.	0.06		1
19	Darlington County Plant	Sumter	230.00	230.00	DC-SSP	5.68		2
20	Darlington County Plant	Sumter	230.00	230.00	W-H Fr.	48.01		1
21	Darlington County Plant	Laurinburg	230.00	230.00	W-H Fr.	34.39		1
22	Florence	Kingstree	230.00	230.00	W-H Fr.	49.46		1
23	Florence	Latta	230.00	230.00	W-H Fr.	23.49		1
24	Florence	Darlington (SCPSA)	230.00	230.00	W-H Fr.	11.05		1
25	Latta	Marion	230.00	230.00	W-H Fr.	8.36		1
26	MARION	SCPSA MARION NORTH	230.00	230.00	S-HFR	0.07		1
27	MARION	SCPSA MARION SOUTH	230.00	230.00	S-HFR	0.08		1
28	MARION	WHITEVILLE	230.00	230.00	S-SP	21.41		1
29	Robinson Plant	Florence	230.00	230.00	DC-T	1.40		2
30	Robinson Plant	Florence	230.00	230.00	W-H Fr.	38.41		1
31	Robinson Plant	Rockingham	230.00	230.00	S-SP	0.23		1
32	Robinson Plant	Rockingham	230.00	230.00	W-H Fr.	40.35		1
33	Robinson Plant	Darlington (SCPSA)	230.00	230.00	DC-T	0.60		2
34	Robinson Plant	Darlington (SCPSA)	230.00	230.00	W-H Fr.	17.95		1
35	Robinson Plant	Sumter	230.00	230.00	W-H Fr.	40.56	0.60	1
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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	Sumter	Canadys (SCE&G)	230.00	230.00	DC-T	7.26		2
2	Sumter	Canadys (SCE&G)	230.00	230.00	W-H Fr.	22.90		1
3	Sumter	Wateree Plant (SCE&G)	230.00	230.00	W-H Fr.	16.58	7.26	1
4	Weatherspoon	Latta	230.00	230.00	W-HFR	21.35		1
5	Tap Point	Bishopville	230.00	230.00	W-H Fr.	0.16		1
6	Tap Point	Cheraw Cash Rd.	230.00	230.00	S-SP	1.08		1
7	Tap Point	Cheraw Reid Park	230.00	230.00	W-H Fr.	5.30		1
8	Tap Point	Dillon North	230.00	230.00	S-SP	3.51		1
9	Tap Point	Dillon Maple	230.00	230.00	W-H Fr.	4.39		1
10	Tap Point	Dovesville Nucor	230.00	230.00	W-H Fr.	6.81		1
11	Tap Point	Elliott	230.00	230.00	W-H Fr.	2.15		1
12	Tap Point	Florence Cashua	230.00	230.00	C-SP	1.30		1
13	Tap Point	Florence Ebenezer	230.00	230.00	W-H Fr.	0.08		1
14	Tap Point	Florence West	230.00	230.00	W-H Fr.	0.03		1
15	Tap Point	Hartsville Segars Mill	230.00	230.00	W-H Fr.	0.06		1
16	Tap Point	Hartsville Talley Metals	230.00	230.00	W-HFR	0.31		1
17	Tap Point	Hartsville Talley Metals	230.00	230.00	S-SP	0.74		1
18	Tap Point	Kingstree North	230.00	230.00	W-H Fr.	0.14		1
19	Tap Point	Lake City	230.00	230.00	W-H Fr.	0.08		1
20	Tap Point	McColl	230.00	230.00	W-H Fr.	0.90		1
21	Tap Point	Olanta	230.00	230.00	W-H Fr.	0.05		1
22	Tap Point	Society Hill	230.00	230.00	W-SP	1.13		1
23	Tap Point	Summerton	230.00	230.00	W-HFR	2.70		1
24	Tap Point	Sumter Alice Drive	230.00	230.00	W-H Fr.	0.30		1
25	Tap Point	Sumter North	230.00	230.00	S-SP	0.73		1
26	Tap Point	Sumter Wedgefield Rd.	230.00	230.00	W-H Fr.	0.05		1
27	Tap Point	Eden Solar	230.00	230.00	S-HFR	0.06		1
28	Tap Point	Warsaw Solar	230.00	230.00	S-HFR	0.06		1
29	Jacksonville	New Bern	230.00	230.00	S-HFR	0.38		1
30	Tot. 230kV Lines							
31								
32								
33								
34	Tot. 115kV Lines				Tower and	2,562.88	57.34	161
35								
36					TOTAL	6,139.69	141.10	635

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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	Tot. 66kV - 69kV Lines				Tower and	11.92	2.17	2
3								
4	Expenses (Columns M & N)							
5								
6	Tot. KV Lines							
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	6,139.69	141.10	635

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)			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)	
1590MCMA(B)								1
1590MCMA(B)								2
3-1590MCMA								3
3-1590MCMA								4
1590MCMA(B)								5
2515MCMA(B)								6
2515MCMA(B)								7
	23,557,293	73,392,491	96,949,784					8
2-1272MCMA								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
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1109MCMA								28
1272&1109MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
2515MCMA								33
2500MCMA								34
1272&2515MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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	04/13/2017	End of 2016/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.
2515MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272&2515MCMA								10
2515MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA								14
1272MCMA								15
1272MCMA								16
1272MCMA								17
795MCMA								18
1590MCMA								19
1590MCMA								20
2515&1272MCMA(								21
1272MCMA(B)								22
1272MCMA(B)								23
1272MCMA(B)								24
795&1272MCMA(B)								25
1272&2515MCMA								26
2515MCMA								27
2515&1272MCMA								28
1272MCMA(B)								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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	04/13/2017	End of 2016/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)	
1590MCMA								1
1590MCMA								2
1272&556MCMA(B)								3
1272MCMA								4
2515MCMA								5
2515MCMA								6
2515MCMA								7
1272&2515MCMA								8
1272MCMA(B)								9
1272MCMA(B)								10
1272MCMA(B)								11
2-1590MCMA								12
2-1590MCMA								13
2-1590MCMA								14
2515MCMA								15
2515MCMA								16
2515&1272MCMA(								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
1272MCMA								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
1272MCMA								29
1272MCMA(B)								30
2515&1272MCMA(								31
1272MCMA(B)								32
1272MCMA(B)								33
1272MCMA(B)								34
1272MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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.
1272MCMA								1
(1272MCMA)								2
1590MCMA								3
1590MCMA								4
1590MCMA								5
21590MCMA								6
21590MCMA								7
2-1590MCMA								8
2-1590MCMA								9
1109MCMA								10
1272&546MCMA(B)								11
546MCMA(B)								12
1272MCMA(B)								13
2515&1272MCMA(								14
1272MCMA(B)								15
1272MCMA(B)								16
1272MCMA(B)								17
1272MCMA(B)								18
1272MCMA(B)								19
1272MCMA(B)								20
2-1590MCMA								21
1590MCMA(B)								22
1590MCMA(B)								23
1272MCMA								24
1272&556MCMA(B)								25
1590MCMA								26
1590MCMA								27
1590MCMA								28
1272MCMA								29
1272MCMA								30
795MCMA								31
1272MCMA								32
1272MCMA								33
795MCMA								34
1272MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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	04/13/2017	End of 2016/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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1272MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
2515MCMA								5
2515&1272MCMA(								6
1272MCMA								7
1272MCMA								8
1590MCMA								9
1590MCMA								10
1590MCMA								11
2515&1272MCMA(								12
1272MCMA(B)								13
1272MCMA(B)								14
2-1272MCMA								15
1272 MCMA								16
1272 MCMA								17
1272 MCMA								18
1272 MCMA								19
2515 MCMA								20
1590MCMA								21
1272MCMA(B)								22
2515MCMA								23
1272MCMA(B)								24
2515&1272MCMA(								25
1272MCMA(B)								26
1272MCMA								27
1272MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA(B)								33
1272MCMA								34
1272MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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.
	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(B)								8
2-1272MCMA(B)								9
1272MCMA(B)								10
21590MCMA								11
21590MCMA								12
21590MCMA(B)								13
21590MCMA(B)								14
21590MCMA								15
954MCMA								16
1272MCMA								17
1272MCMA								18
2-1590MCMA								19
2-1590MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1590MCMA								24
1590MCMA								25
1590MCMA								26
1590MCMA								27
1590MCMA								28
1590MCMA								29
1590MCMA								30
1590MCMA								31
1590MCMA								32
1272MCMA								33
1590MCMA								34
1272MCMA								35
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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) 04/13/2017	Year/Period of Report End of 2016/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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1272&1590MCMA								1
1272MCMA(B)								2
1272MCMA(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
2515MCMA								12
1272&2515MCMA(								13
2-1590MCMA								14
2-1590MCMA								15
2515&1272MCMA(								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
(1272MCMA)								20
1272MCMA								21
1272MCMA								22
1272MCMA(B)								23
1272MCMA(B)								24
1272MCMA								25
1272MCMA								26
1272MCMA								27
1272&2515MCMA								28
1272MCMA								29
1590MCMA(B)								30
795MCMA								31
795MCMA								32
1272MCMA(B)&251								33
1272MCMA(B)								34
795MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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)			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
795MCMA								3
795MCMA								4
1272MCMA								5
795MCMA								6
795MCMA								7
1272MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
1272MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
1272MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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.
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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.
795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
1272MCMA								6
795MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1272MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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	04/13/2017	End of 2016/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.
795MCMA								1
1272MCMA								2
1272MCMA								3
1590MCMA(B)								4
795MCMA								5
1272MCMA								6
795MCMA								7
1272MCMA								8
795MCMA								9
1590MCMA								10
795MCMA								11
795MCMA								12
1272MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
1590MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
1272MCMA								23
1272MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1590MCMA								28
795MCMA								29
795 MCMA								30
795 MCMA								31
1590MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	36

TRANSMISSION LINE STATISTICS (Continued)

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795MCMA								1
795MCMA								2
1272MCMA								3
795MCMA								4
1272MCMA								5
1272MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
2-2500MCMA								13
1272MCMA								14
1590MCMA								15
2515MCMA								16
2515MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
2515MCMA								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
1590MCMA								25
2-1272MCMA								26
2-1272MCMA								27
1590MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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	04/13/2017	End of 2016/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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795MCMA								1
795MCMA								2
1272MCMA								3
1272MCMA								4
795MCMA								5
795MCMA								6
1272MCMA								7
795MCMA								8
795MCMA								9
1272MCMA								10
795MCMA								11
795MCMA								12
1590MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
1590MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
1272MCMA								29
	120,248,048	677,059,246	797,307,294					30
								31
								32
								33
	34,773,887	448,989,922	483,763,809					34
								35
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	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	04/13/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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.
								1
	57,228	2,308,999	2,366,227					2
								3
				844,247	23,517,924		24,362,171	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
	178,636,456	1,201,750,658	1,380,387,114	844,247	23,517,924		24,362,171	36

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	TAP POINT	ROWAN CREEK SOLAR	0.08	S-HFR		1	1
2	TAP POINT	BRUNSWICK EMC DAWS	0.02	S-HFR		1	1
3	TAP POINT	ROSLIN SOLAR	0.05	S-HFR		1	1
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
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32							
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35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.15			3	3

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	04/13/2017	End of 2016/Q4

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) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	MCMA	FLAT	230		133,500	596,294	61,854	791,648	1
1272	MCMA	FLAT	230		98,290	818,863	5,908	923,061	2
336	MCMA	FLAT	115		150,357	340,713	29,129	520,199	3
									4
									5
									6
									7
									8
									9
									10
									11
									12
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									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					382,147	1,755,870	96,891	2,234,908	44

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 (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	Beard 115kV Beard	D-U	115.00	13.00	
32	Beaufort 115kV Beaufort	D-U	115.00	12.00	
33	Beaverdam 115kV Asheville	D-U	115.00	24.00	
34	Belfast 115kV Goldsbsoro	D-U	115.00	23.00	
35	Benson 230kV Benson	D-U	230.00	24.00	
36	Beulaville 115kV Beulaville	D-U	115.00	23.00	
37	Biltmore 115kV Asheville	D-U	115.00	12.00	
38	Biscoe 115kV Biscoe	D-U	115.00	24.00	
39	Biscoe 230kV Bisco	T-U	230.00	115.00	
40	Black Mountain 115kV Black Mountain	D-U	115.00	13.00	

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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Bladenboro 115kV Bladenboro	D-U	115.00	24.00	
2	Blewett H.E. Plant Lilesville	T-A Gen Step-Up	115.00	13.20	
3	Blewett H.E. Plant Lilesville	T-A Gen Step-Up	115.00	4.00	
4	Bridgeton 115kV Bridgeton	D-U	115.00	24.00	
5	Brunswick S.E. Plant Wilmington	T-A Gen Step-Up	230.00	24.00	
6	Buies Creek 230kV Buies Creek	D-U	230.00	24.00	
7	Burgaw 115kV Burgaw	D-U	115.00	23.00	
8	Butler Bldg 115kv Laurinburg NC	D-U	115.00	12.00	
9	Bynum 230kV Bynum	D-U	230.00	24.00	
10	Camp Lejeune French Creek 230kV Jacksonville	D-U	230.00	13.80	
11	Candler 115 kV Candler	D-U	115.00	24.00	
12	Candor 115kV Candor	D-U	115.00	24.00	
13	Cane River 230kV Burnsville	T-U	230.00	115.00	
14	Canton 115kV Canton	D-U	115.00	12.00	
15	Cape Fear S.E. Plant Moncure	T-A	230.00	115.00	13.80
16	Caraleigh 230kV Raleigh	D-U	230.00	24.00	
17	Carolina Beach 115kV Carolina Beach	D-U	115.00	24.00	
18	Carthage 115kV Carthage	D-U	115.00	12.00	
19	Cary 230kV Cary	D-U	230.00	23.00	
20	Cary Evans Rd. 230kV Cary	D-U	230.00	24.00	
21	Cary Piney Plains 230kV Cary	D-U	230.00	24.00	
22	Cary Regency Park 230kV Cary	D-U	230.00	23.00	
23	Cary Trenton Road 230 kV Cary	D-U	230.00	24.00	
24	Cary Triangle Forest 230kV Cary	D-U	230.00	23.00	
25	Castalia 230 kV Castalia	D-U	230.00	24.00	
26	Castle Hayne 115kV Wilmington	D-U	115.00	24.00	
27	Castle Hayne 230kV Wilmington	T-U	230.00	115.00	13.80
28	Catherine Lake 230kV Jacksonville	D-U	230.00	24.00	
29	Chadbourn 115kV Chadbourn	D-U	115.00	24.00	
30	Cherry Point #1 115kV Havelock	D-U	115.00	12.00	
31	Cherry Point #2 115kV Havelock	D-U	115.00	12.00	
32	Chestnut Hills 115kV Raleigh	D-U	115.00	24.00	
33	Chocowinity 230kV Chocowinity	D-U	230.00	23.00	
34	Clarkton 115kV Clarkton	D-U	115.00	24.00	
35	Clayton 115kV Clayton	D-U	115.00	24.00	
36	Clayton Industrial 115kV Clayton	D-U	115.00	24.00	
37	Clifdale 230kV Clifdale	D-U	230.00	24.00	
38	Clinton 230kV Clinton	T-U	230.00	115.00	13.80
39	Clinton Ferrell St. 115kV Clinton	D-U	115.00	23.00	
40	Clinton (N) 115kV Clinton	D-U	115.00	23.00	

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SUBSTATIONS

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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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Concord 230kV Concord	T-U	230.00	115.00	
2	Craggy 230kV Craggy	T-U	230.00	115.00	
3	Cumberland 500kV Fayetteville	T-U	500.00	230.00	13.80
4	Delco 115kV Delco	D-U	115.00	24.00	
5	Delco 230kV Delco	T-U	230.00	115.00	13.80
6	Dover 230kV Kinston	D-U	230.00	24.00	
7	Duncan 230kV Garner	D-U	230.00	24.00	
8	Dunn 230kV Dunn	D-U	230.00	23.00	
9	Durham 500kV Leesville	T-U	500.00	230.00	13.80
10	Eagle Island 115kV Wilmington	D-U	115.00	24.00	
11	Edmondson 230kV Raleigh	D-U	230.00	24.00	
12	Elizabethtown 115kV Elizabethtown	D-U	115.00	24.00	
13	Elk Mountain 115kV Asheville	D-U	115.00	24.00	
14	Ellerbe 230kV Ellerbe	D-U	230.00	23.00	
15	Elm City 115kV Elm City	D-U	115.00	24.00	
16	Emma 115kV Asheville	D-U	115.00	12.00	
17	Enka 230kV Enka	T-U	230.00	115.00	
18	Enka Sardis Rd. 115kV Enka	D-U	115.00	24.00	
19	Erwin 230kV Erwin	T-U	230.00	115.00	13.80
20	Erwin 230kV Erwin	D-U	115.00	24.00	12.00
21	Erwin 230kV Erwin	D-U	115.00	24.00	
22	Erwin Mills 115kv Erwin	D-U	115.00	12.00	
23	Fair Bluff 115kV Fair Bluff	D-U	115.00	24.00	
24	Fairmont 115kV Fairmont	D-U	115.00	23.00	
25	Fairview 115kV Fairview	D-U	115.00	12.00	
26	Falls 230kV Raleigh	D-U	230.00	24.00	
27	Falls 230kV Raleigh	T-U	230.00	115.00	
28	Farmville 230kV Farmville	D-U	230.00	12.00	
29	Fayetteville 230kV Fayetteville	D-U	115.00	24.00	13.20
30	Fayetteville 230kV Fayetteville	T-U	230.00	115.00	
31	Fayetteville Slocomb 115kV Slocomb	D-U	115.00	12.00	
32	Folkstone 230kV Holly Ridge	T-U	230.00	115.00	
33	Four Oaks 230kV Four Oaks	D-U	230.00	23.00	
34	Ft Bragg Longstreet Rd 230 kV Fort Bragg	D-U	230.00	12.00	
35	Ft. Bragg Main 230kV Fayetteville	D-U	230.00	23.00	
36	Ft. Bragg Main 230kV Fayetteville	D-U	230.00	12.00	
37	Ft. Bragg Woodruff St. 230kV Fayetteville	T-U	230.00	12.00	
38	Ft. Bragg Woodruff St. 230kV Fayetteville	T-U	230.00	115.00	
39	Franklinton Novo 115kV	D-U	115.00	12.00	
40	Franklinton 115kV Franklinton	D-U	115.00	24.00	

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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	Fremont 115kV Fremont	D-U	115.00	12.00	
2	Fuquay 230kV Fuquay	D-U	230.00	23.00	
3	Fuquay Bells Lake 230kV Fuquay	D-U	230.00	23.00	
4	Garland 230kV Garland	D-U	230.00	23.00	
5	Garner 115kV Garner	D-U	115.00	24.00	
6	Garner I-40 230kV Garner	D-U	230.00	24.00	
7	Garner Panther Branch 230kV Wake Co.	D-U	230.00	23.00	
8	Garner Tryon Hills 115kV Garner	D-U	115.00	24.00	
9	Garner White Oak 230kV Garner	D-U	230.00	24.00	
10	Global Trans Park 115kV Kinston	D-U	115.00	23.00	
11	Godwin 115kV Godwin	D-U	115.00	23.00	
12	Goldsboro City 115kV Goldsboro	D-U	115.00	12.00	
13	Goldsboro Hemlock 115kV Goldsboro	D-U	115.00	12.00	
14	Goldsboro Langston 115kV Goldsboro	D-U	115.00	24.00	
15	Goldsboro-Weil 115kV Goldsboro	D-U	115.00	24.00	
16	Grantham 230kV Grantham	D-U	230.00	24.00	
17	Green Level 230kV Green Level	D-U	230.00	24.00	
18	Grifton 115kV Grifton	D-U	115.00	23.00	
19	Hamlet 230kV Hamlet	D-U	230.00	24.00	
20	Havelock 230kV Havelock	D-U	115.00	23.00	
21	Havelock 230kV Havelock	T-U	230.00	115.00	13.80
22	Hazelwood 115kV Hazelwood	D-U	115.00	24.00	
23	Henderson 230kV Henderson	T-U	230.00	115.00	13.20
24	Henderson 230kV Henderson	D-U	115.00	24.00	
25	Henderson East 230kV Henderson	D-U	230.00	24.00	
26	Henderson North 115kV Henderson	D-U	115.00	24.00	
27	Holly Ridge 115kV Holly Ridge	D-U	115.00	23.00	
28	Holly Springs 230kV Holly Springs	D-U	230.00	24.00	
29	Holly Springs Industrial 230kV Holly Springs	D-U	230.00	24.00	
30	Hope Mills Church St. 115kV Hope Mills	D-U	115.00	23.00	
31	Hope Mills Rockfish Rd. 230kV Hope Mills	D-U	230.00	24.00	
32	Jacksonville 230kV Jacksonville	T-U	230.00	115.00	
33	Jacksonville City 115kV Jacksonville	D-U	115.00	24.00	
34	Jacksonville Northwoods 115kV Jacksonville	D-U	115.00	23.00	
35	Jacksonville Tarawa 230kV Jacksonville	D-U	230.00	24.00	
36	Jonesboro 230kV Sanford	D-U	230.00	24.00	
37	Kings Bluff 115kV Wilmington	D-U	115.00	23.00	
38	Kinston 115kV Kinston	D-U	115.00	24.00	
39	Kinston DuPont 115kV Kinston	D-U	115.00	12.00	
40	Kinston DuPont 230kV Kinston	T-U	230.00	115.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Knightdale Square D 230kV Knightdale	D-U	230.00	24.00	
2	Knightdale 115kV Knightdale	D-U	115.00	23.00	
3	Kornegay 115kV Kornegay	D-U	115.00	23.00	
4	LaGrange 115kV LaGrange	D-U	115.00	12.00	
5	Lake Junaluska 115kV Lake Junaluska	D-U	115.00	24.00	
6	Lake Wacamaw 115kV Lake Waccamaw	D-U	115.00	24.00	
7	Lakestone 115kV Raleigh	D-U	115.00	12.00	
8	Lakeview 115kv Carthage	D-U	115.00	24.00	
9	Laurel Hill 230kV Laurel Hill	D-U	230.00	23.00	
10	Laurinburg 230kV Laurinburg	T-U	230.00	115.00	13.80
11	Laurinburg 230kV Laurinburg	D-U	115.00	24.00	12.00
12	Laurinburg City 230kV Laurinburg	D-U	230.00	23.00	
13	Lee Combined Cycle Plant	T-A	230.00	115.00	
14	Lee 230kV Goldsboro	T-U	230.00	115.00	
15	Lee 230kV Goldsboro	T-U	115.00	13.80	
16	Leesville Wood Valley 230kV Raleigh	D-U	230.00	24.00	
17	Leicester 115kV Leicester	D-U	115.00	24.00	
18	Leland 115kV Wilmington	D-U	115.00	24.00	
19	Leland Industrial 115kV Leland	D-U	115.00	24.00	
20	Liberty 115kV Liberty	D-U	115.00	23.00	
21	Lillington 115kV Lillington	D-U	115.00	24.00	
22	Littleton 115kV Littleton	D-U	115.00	24.00	
23	Louisburg 115kV Louisburg	D-U	115.00	23.00	
24	Lumberton 115kV Lumberton	D-U	115.00	24.00	
25	Maggie Valley 115kV Maggie Valley	D-U	115.00	24.00	
26	Marshall H.E. Plant Marshall	D-U	115.00	23.00	
27	Marshall H.E. Plant Marshall	T-U Gen Step-Up	23.00	4.00	
28	Masonboro 230kV Wilmington	D-U	230.00	23.00	
29	Maxton 115kV Maxton	D-U	115.00	24.00	
30	Maxton Airport 115kV Maxton	D-U	115.00	23.00	
31	Mayo S.E. Plant Roxboro	T-A Gen Step-Up	500.00	19.90	
32	Method 230kV Raleigh	D-U	115.00	12.00	
33	Method 230kV Raleigh	T-U	230.00	115.00	13.80
34	Micaville 115kV Micaville	D-U	115.00	12.00	
35	Milburnie 230kV Raleigh	D-U	115.00	23.00	
36	Milburnie 230kV Raleigh	T-U	230.00	115.00	13.80
37	Moncure 115kV Moncure	D-U	115.00	24.00	
38	Monte Vista 115kV Asheville	D-U	115.00	23.00	
39	Mordecai 115kV Raleigh	D-U	115.00	12.00	
40	Morehead 115kV Morehead	D-U	115.00	12.00	

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1	Morehead Wildwood 230kV	D-U	115.00	24.00	
2	Morehead Wildwood 230kV Morehead	T-U	230.00	115.00	
3	Morrisville 230kV Morrisville	D-U	230.00	23.00	
4	Mount Gilead 115kV Mount Gilead	D-U	115.00	12.00	
5	Mount Gilead Industrial 115kV Mount Gilead	D-U	115.00	13.00	
6	Mount Olive 115kV Mount Olive	D-U	115.00	12.00	
7	Mount Olive 230kV Mount Olive	T-U	230.00	115.00	
8	Mount Olive West 115kV Mount Olive	D-U	115.00	24.00	
9	Murrayville 230kV New Hanover	D-U	230.00	23.00	
10	Nagel (APCO) 500kV Hawkins, Tn.	T-U	500.00	230.00	13.80
11	Nashville 115kV Nashville	D-U	115.00	23.00	
12	Neuse 115kV Neuse	D-U	115.00	23.00	
13	New Bern 230kV New Bern	T-U	230.00	115.00	13.20
14	New Bern Amital 115kV New Bern	D-U	115.00	12.00	
15	New Bern West 230kV New Bern	D-U	230.00	23.00	
16	New Hill 230kV New Hill	D-U	230.00	23.00	
17	New Hope 115kV Goldsboro	D-U	115.00	23.00	
18	New Salem 115kV Swannanoa	D-U	115.00	12.00	
19	Newport 115kV Newport	D-U	115.00	23.00	
20	Newton Grove 230kV Newton Grove	D-U	230.00	23.00	
21	North River 115kV Beaufort	D-U	115.00	34.50	
22	Oteen 115kV Asheville	D-U	115.00	12.00	
23	Oxford North 230kV Oxford	D-U	230.00	23.00	
24	Oxford South 230kV Oxford	D-U	230.00	23.00	
25	Pembroke 115kV Pembroke	D-U	115.00	23.00	
26	Person 500kV Roxboro	T-U	500.00	230.00	13.80
27	Person 500kV Roxboro	D-U	230.00	24.00	
28	Pine Lake 230kV Raleigh	D-U	230.00	23.00	
29	Pinehurst 115kV Pinehurst	D-U	115.00	24.00	
30	Pisgah Forest (Duke) 230kV Brevard	T-U	115.00	100.00	13.00
31	Pittsboro 230kV Pittsboro	D-U	230.00	23.00	
32	Princeton 115kV Princeton	D-U	115.00	23.00	
33	Raeford 115kV Raeford	D-U	115.00	12.00	
34	Raeford 230kV Raeford	T-U	230.00	115.00	
35	Raeford South 115kV Raeford	D-U	115.00	12.00	
36	Raleigh 115kV Raleigh	D-U	115.00	12.00	
37	Raleigh Atlantic Avenue 115kV Raleigh	D-U	115.00	23.00	
38	Raleigh Blue Ridge 230kV Raleigh	D-U	230.00	23.00	
39	Raleigh Brier Creek 230kV Raleigh	D-U	230.00	24.00	
40	Raleigh Durham Airport 230-23kV Raleigh	D-U	230.00	23.00	

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1	Raleigh East St. 230kV Raleigh	D-U	230.00	12.00	
2	Raleigh Foxcroft 230kV Raleigh	D-U	230.00	24.00	
3	Raleigh Harrington Street 115kV Raleigh	D-U	115.00	13.20	
4	Raleigh Homestead 230kV Raleigh	D-U	230.00	24.00	
5	Raleigh Honeycutt 230kV Raleigh	D-U	230.00	24.00	
6	Raleigh Leesville Road 230kV Raleigh	D-U	230.00	24.00	
7	Raleigh Northside 115kV Raleigh	D-U	115.00	12.00	
8	Raleigh Oakdale 230kV Raleigh	D-U	230.00	23.00	
9	Raleigh Prison Farm 230kV Raleigh	D-U	230.00	24.00	
10	Raleigh Six Forks 230kV Raleigh	D-U	230.00	24.00	
11	Raleigh South 115kV Raleigh	D-U	115.00	23.00	
12	Raleigh Timberlake 115kV Raleigh	D-U	115.00	23.00	
13	Raleigh Worthdale 230kV Raleigh	D-U	230.00	23.00	
14	Raleigh Yonkers Rd 115kV Raleigh	D-U	115.00	23.00	
15	Ramseur 115kV Ramseur	T-U	115.00	69.00	12.00
16	Ramseur 115kV Ramseur	D-U	115.00	24.00	
17	Red Springs 115kV Red Springs	D-U	115.00	23.00	
18	Reynolds 115kV Asheville	D-U	115.00	12.00	
19	Rhems 230kV New Bern	D-U	230.00	24.00	
20	Rhems 115kV New Bern	D-U	115.00	24.00	
21	Richmond 500kV Rockingham	T-U	500.00	230.00	13.80
22	Richmond County Plant Hamlet	T-A Gen Step-Up	230.00	18.00	13.80
23	Robbins 115kV Robbins	D-U	115.00	24.00	
24	Rockingham 230kV Rockingham	T-U	230.00	115.00	13.80
25	Rockingham 230kV Rockingham	D-U	115.00	23.00	
26	Rockingham Aberdeen Rd. 230kV Rockingham	D-U	230.00	23.00	
27	Rockingham West 115kV Rockingham	D-U	115.00	24.00	
28	Rocky Mount 230kV Rocky Mount	D-U	115.00	24.00	
29	Rocky Mount 230kV Rocky Mount	T-U	230.00	69.00	13.20
30	Rocky Mount 230kV Rocky Mount	T-U	230.00	115.00	13.80
31	Rocky Point 230KV Rocky Point	D-U	230.00	24.00	
32	Rolesville 230kV Rolesville	D-U	230.00	24.00	
33	Rose Hill 230kV Rose Hill	D-U	230.00	24.00	
34	Roseboro 115kV Roseboro	D-U	115.00	23.00	
35	Rowland 230kV Rowland	D-U	230.00	24.00	
36	Rosewood 115KV Goldsboro	D-U	115.00	24.00	
37	Roxboro 115kV Roxboro	D-U	115.00	24.00	
38	Roxboro 115kV Roxboro	T-U	115.00	24.00	
39	Roxboro Bowmantown Rd. 230kV Roxboro	D-U	230.00	23.00	
40	Roxboro South 230kV Roxboro	D-U	230.00	24.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 1	230.00	22.00	
2	Roxboro S.E. Plant Roxboro	TA Gen St-Dwn ICTG	138.00	4.00	
3	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 4	230.00	23.50	
4	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 3	230.00	23.50	
5	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 2	230.00	23.50	
6	Roxboro S.E. Plant (Cooling Tower) Roxboro	T-A	230.00	4.00	
7	RTP 230KV Morrisville	D-U	230.00	24.00	
8	Samaria 115kV Samaria	D-U	115.00	24.00	
9	Sanford Deep River 230kV Sanford	D-U	230.00	24.00	
10	Sanford Garden St. 230kV Sanford	D-U	230.00	23.00	
11	Sanford Horner Blvd 230kV Sanford	D-U	230.00	24.00	
12	Sanford US #1 230-23kV Sanford	D-U	230.00	24.00	
13	Scotts Hill 230kV Scotts Hill	D-U	230.00	24.00	
14	Seagrove 115kV Seagrove	D-U	115.00	12.00	
15	Selma 230kV Selma	D-U	115.00	12.00	
16	Selma 230kV Selma	D-U	115.00	24.00	13.20
17	Selma 230kV Selma	T-U	230.00	115.00	
18	Seymour Johnson 115kV Goldsboro	D-U	115.00	12.00	
19	Shannon 115kV Shannon	D-U	115.00	23.00	
20	Shearon Harris S.E. Plant New Hill	T-A Gen Step-Up	230.00	21.50	
21	Siler City 115kV Siler City	D-U	115.00	24.00	
22	Siler City 230kV Siler City	T-U	230.00	115.00	13.80
23	Siler City Hwy 64E 230kV Siler City	D-U	230.00	24.00	
24	Skyland 115-23kV Skyland	D-U	115.00	24.00	
25	Smithfield 115kV Smithfield	D-U	115.00	12.00	
26	Snow Hill 115kV Snow Hill	D-U	115.00	23.00	
27	Southern Pines 115kV Southern Pines	D-U	115.00	23.00	
28	Southport 230kV Southport	D-U	230.00	23.00	
29	So. Pines Center Pk. 115kV Southern Pines	D-U	115.00	23.00	
30	Spring Hope 115kV Spring Hope	D-U	115.00	23.00	
31	Spring Lake 115kV Spring Lake	D-U	230.00	24.00	
32	Spruce Pine 115kV Spruce Pine	D-U	115.00	23.00	
33	Stallings Crossroads 115kV Stallings X-Road	D-U	115.00	23.00	
34	St. Pauls 115kV St. Pauls	D-U	115.00	23.00	
35	Sutton CC Plant Wilmington	T-A Gen St-Up SCC01A	115.00	16.50	
36	Sutton S.E. Plant Wilmington	TAGenSt-Up 2A,2B	115.00	13.20	
37	Sutton S.E. Plant Wilmington	TA Gen Step-Up ICTG1	115.00	13.80	
38	Suton CC Plant Wilmington	TA G St-Up STI SCC01	230.00	23.50	
39	Swannanoa 115kV Swannanoa	D-U	115.00	12.00	
40	Swansboro 230kV Swansboro	D-U	230.00	23.00	

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	04/13/2017	End of 2016/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.
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	Tillery H.E. Plant Mt. Gilead	T-A Gen Step-Up	115.00	13.20	
2	Topsail 230kV Hampstead	D-U	230.00	23.00	
3	Troy 115kV Troy	D-U	115.00	12.00	
4	Troy Burnette St 115kV Troy	D-U	115.00	12.00	
5	Vander 115kV Vander	T-U	115.00	24.00	
6	Vanderbilt 115kV Asheville	D-U	115.00	12.00	
7	Vander Dak 115kV	D-U	115.00	12.00	
8	Vander Dak/DuPont/Praxair	D-U	115.00	12.00	
9	VIsta 115kV	D-U	115.00	24.00	
10	Wadesboro 230V Wadesboro	D-U	230.00	24.00	
11	Wadesboro-Bowman Sch 230kV Wadesboro	D-U	230.00	24.00	
12	Wake 500kV Knigthdale	T-U	500.00	230.00	13.80
13	Wake Forest 115kV Wake Forest	T-U	115.00	69.00	13.20
14	Wake Tech 230kV Raleigh	D-U	230.00	24.00	
15	Wallace 115kV Wallace	T-U	115.00	69.00	13.20
16	Wallace 115kV Wallace	D-U	115.00	24.00	
17	Wallace 230kV Wallace	T-U	230.00	115.00	13.80
18	Walters H.E.P. Waterville	T-A	161.00	115.00	13.80
19	Walters H.E.P. Waterville	D-A	115.00	12.00	
20	Walters H.E.P. Waterville	T-A Gen Step-Up	115.00	12.00	
21	Walters H.E.P. Waterville	T-A	138.00	115.00	8.60
22	Warrenton 115kV Warrenton	D-U	115.00	24.00	
23	Warsaw 230kV Warsaw	D-U	230.00	24.00	
24	Wayne County Plant	T-A	230.00	18.00	
25	Waynesville 115kV Waynesville	D-U	115.00	12.00	
26	Weatherspoon 230kV Lumberton	D-U	230.00	24.00	
27	Weatherspoon Plant Lumberton	T-A	230.00	115.00	
28	Weatherspoon Plant Lumberton	T-A Gen Step-Up	115.00	13.20	
29	Weaverville 115kV Weaverville	D-U	115.00	12.00	
30	Wendell 230kV Wendell	D-U	230.00	23.00	
31	West Asheville 115kV Asheville	D-U	115.00	12.00	
32	West End 230kV West End	D-U	230.00	24.00	
33	West End 230kV West End	T-U	230.00	115.00	13.80
34	Whiteville 115kV Whiteville	D-U	115.00	23.00	
35	Whiteville 230kV Whiteville	T-U	230.00	115.00	13.80
36	Whiteville SE Regional Park 115kV Whiteville	D-U	115.00	24.00	
37	Wilmington Cedar Ave. 230kV Wilmington	D-U	230.00	23.00	
38	Wilmington East 230kV Wilmington	D-U	230.00	24.00	
39	Wilmington Ogden 230kV Wilmington	D-U	230.00	23.00	
40	Wilm. 9th & Orange 230kV Wilmington	D-U	230.00	24.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Wilmington River Road 115KV Wilmington	D-U	115.00	24.00	
2	Wilm. Sunset Pk. 115kV Wilmington	D-U	115.00	24.00	
3	Wilm. Winter Pk. 230kV Wilmington	D-U	230.00	23.00	
4	Wilson 230kV Wilson	T-U	230.00	115.00	13.80
5	Wilson's Mills 230kV Wilson's Mills	D-U	230.00	24.00	
6	Wommack 230kV Kinston	T-U	230.00	115.00	13.80
7	Wrightsville Beach 230kV Wrightsville Beach	D-U	230.00	24.00	
8	Yanceyville 230kV Yanceyville	D-U	230.00	12.00	
9	Youngsville 115kV Youngsville	D-U	115.00	24.00	
10	Zebulon 115kV Zebulon	T-U	115.00	69.00	
11	Zebulon 115kV Zebulon	D-U	115.00	24.00	
12	Zebulon 230kV Zebulon	T-U	230.00	115.00	
13	Zebulon 230kV Zebulon	T-U	115.00	69.00	
14					
15					
16	South Carolina Substations				
17	----------------------				
18	Andrews 115kV Andrews	D-U	115.00	24.00	
19	Bennettsville 230kV Bennettsville	D-U	230.00	24.00	
20	Bethune 115kV Bethune	D-U	115.00	12.00	
21	Bishopville 230kV Bishopville	D-U	230.00	24.00	
22	Camden 230kV Camden	D-U	230.00	24.00	
23	Camden 230kV Camden	T-U	230.00	115.00	
24	Camden Steeplechase 115kV Camden	D-U	115.00	24.00	
25	Cheraw 115kV Cheraw	D-U	115.00	24.00	
26	Cheraw Cash Road 230kV Cheraw	D-U	230.00	23.00	
27	Cheraw-Reid Park 230kV Cheraw	D-U	230.00	24.00	
28	Chesterfield 115kV Chesterfield	D-U	115.00	24.00	
29	Darlington 115kV Darlington	D-U	115.00	24.00	
30	Darlington I.C. Plant Darlington	T-A Gen Step-Up	230.00	14.00	
31	Darlington Pineville Rd 115kV Darlington	D-U	115.00	24.00	
32	Dillon 115kV Dillon	D-U	115.00	24.00	
33	Dillon-Maple 230kV Dillon	D-U	230.00	24.00	
34	Dillon North 230kV Dillon	D-U	230.00	24.00	
35	Elgin 115kV Elgin	D-U	115.00	24.00	
36	Elliott 230kV Elliott	D-U	230.00	24.00	
37	Florence 230kV Florence	D-U	115.00	24.00	
38	Florence 230kV Florence	T-U	230.00	115.00	
39	Florence-Burches X-Rds 115-23kV Florence	D-U	115.00	23.00	
40	Florence Cashua 230kV Florence	D-U	230.00	23.00	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/Q4

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	Florence-Ebenezer 230kV Florence	D-U	230.00	24.00	
2	Florence-Mars Bluff 115kV Florence	D-U	115.00	24.00	
3	Florence-Mount Hope 115kV Florence	D-U	115.00	23.00	
4	Florence-Sardis 230kV Sardis	D-U	230.00	24.00	
5	Florence South 115kV Florence	D-U	115.00	24.00	
6	Florence West 230kV Florence	D-U	230.00	24.00	
7	Hartsville 115kV Hartsville	D-U	115.00	24.00	
8	Hartsville-Segars Mill 230kV Hartsville	D-U	230.00	24.00	
9	Hartsville Sonoco 115kV Hartsville	D-U	115.00	14.00	
10	Hemingway 115kV Hemingway	D-U	115.00	24.00	
11	Jefferson 115kV Jefferson	D-U	115.00	23.00	
12	Kingstree 230kV Kingstree	T-U	230.00	115.00	13.80
13	Kingstree 230kV Kingstree	D-U	115.00	24.00	
14	Kingstree North 230kV Kingstree	D-U	230.00	24.00	
15	Lake City 230kV Lake City	D-U	230.00	24.00	
16	Manning 115kV Manning	D-U	115.00	24.00	
17	Marion 230kV Marion	D-U	115.00	24.00	12.00
18	Marion 230kV Marion	T-U	230.00	115.00	13.80
19	Marion-Bypass 115kV Marion	D-U	115.00	23.00	
20	McColl 230kV McColl	D-U	230.00	24.00	
21	Mullins 115kV Mullins	D-U	115.00	24.00	
22	Nichols 115kV Nichols	D-U	115.00	24.00	
23	Olanta 230kV Olanta	D-U	230.00	24.00	
24	Pageland 115kV Pageland	D-U	115.00	24.00	
25	Pamplico 115kV Pamplico	D-U	115.00	24.00	
26	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	21.50	
27	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	115.00	13.80
28	Shaw Field 115kV Sumter	D-U	115.00	12.00	
29	Society Hill 230kV Society Hill	D-U	230.00	24.00	
30	Summerton 230kV Summerton	D-U	230.00	24.00	
31	Sumter 230kV Sumter	D-U	115.00	23.00	
32	Sumter 230kV Sumter	T-U	230.00	115.00	13.80
33	Sumter Alice Drive 230kV Sumter	D-U	230.00	23.00	
34	Sumter Industrial 115-23kV Sumter	D-U	115.00	23.00	
35	Sumter North 230kV Sumter	D-U	230.00	24.00	
36	Sumter-Wedgefield Rd. 230kV Sumter	D-U	230.00	24.00	
37	Wateree HE.P. (Duke) Sumter	T-A	115.00	100.00	7.00
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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		Total T-A			
2		Total T-U			
3		Total D-A			
4		Total D-U			
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
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33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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.
						1
						2
50	2					3
40	1					4
40	1					5
13	1					6
100	4					7
40	1					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					30
25	4					31
25	1					32
25	1					33
50	2					34
50	2	1	Step Down 23/12kV	3	13	35
25	1					36
55	1					37
25	1		Mb.Sp.(115/23/12kV)	2	33	38
300	1					39
19	3	1				40

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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) (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.
19	3					1
74	1					2
30	1					3
19	3					4
2420	8	1				5
25	1					6
25	1					7
10	3					8
50	2					9
40	1					10
25	1					11
25	1					12
300	3	1				13
80	2					14
650	2					15
63	3					16
50	2					17
25	1					18
50	2					19
90	3					20
90	3					21
50	2					22
40	1					23
50	2					24
25	1					25
100	6					26
500	2					27
25	1					28
19	3					29
50	2					30
25	3	1				31
100	5	1				32
50	2					33
25	1					34
90	3					35
80	2					36
50	2					37
200	1					38
50	3	1				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.
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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.
300	1					1
600	2					2
1000	3	1				3
25	1					4
500	2					5
40	1					6
40	1					7
50	2					8
1125	3	1				9
50	3	1				10
80	2					11
25	1					12
50	2					13
25	1					14
13	2					15
25	1					16
300	1					17
25	1					18
300	2					19
15	3	1				20
25	1					21
25	1					22
7	1					23
40	1					24
30	1					25
40	1					26
600	2					27
25	1					28
25	3	1				29
600	2					30
25	1					31
200	1					32
25	1					33
50	2					34
25	1					35
50	2					36
25	1					37
600	2					38
25	1					39
25	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) (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
50	2					3
15	3	1				4
50	2					5
40	1					6
50	2					7
40	1					8
40	1					9
13	3					10
23	1					11
50	2					12
25	1					13
40	1					14
25	1					15
25	1					16
40	1					17
25	1					18
65	2					19
50	2					20
400	2					21
65	2					22
600	2					23
50	2					24
50	3					25
50	2					26
9	1					27
80	2					28
40	1					29
25	1					30
25	1					31
600	2					32
50	3	1				33
50	2					34
25	1					35
75	3					36
6	3	1				37
50	2					38
100	4					39
300	1					40

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2017	Year/Period of Report End of 2016/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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25	1					1
50	3	1				2
19	3					3
25	1					4
65	2					5
25	1					6
50	2					7
40	1					8
50	2					9
400	2					10
40	6	1				11
50	2					12
						13
600	2					14
13	3					15
90	3					16
50	2					17
25	1					18
50	2					19
25	1					20
50	2					21
25	1					22
31	3	1				23
25	1					24
40	1					25
6	1					26
6	1					27
75	3					28
25	1					29
25	1					30
765	3	1				31
50	2					32
600	2					33
13	1	1				34
50	3	1				35
600	2					36
50	2					37
80	2					38
50	2					39
50	2					40

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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
300	1					2
50	2					3
19	3					4
25	1					5
25	1					6
200	1					7
25	1					8
40	1					9
75		1				10
50	3	1				11
50	2					12
400	2					13
25	1					14
50	2					15
25	1					16
50	3	1				17
30	1					18
25	1					19
25	1					20
25	1	1		3	1	21
50	3	1				22
50	2					23
50	2					24
40	1					25
1000	3	1				26
25	1					27
50	2					28
40	1					29
100	1					30
25	1					31
25	1					32
55	2					33
400	2					34
15	3					35
50	2					36
25	1					37
50	2					38
80	2					39
50	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	04/13/2017	End of 2016/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.
80	2					1
40	1					2
60	2					3
80	2					4
40	1					5
90	3					6
50	2					7
50	2					8
50	2					9
50	2					10
50	2					11
50	2					12
50	2					13
40	1					14
53	3	2		1	2	15
40	1					16
25	1					17
30	1					18
25	1					19
40	1					20
1500	6	1				21
2765	8					22
25	1					23
550	2		230kV Phase Angle	2	1,080	24
50	3	1				25
25	1					26
75	4	1				27
25	1					28
300	2					29
400	2					30
25	1					31
80	2					32
25	1					33
25	1					34
13	1					35
40	1					36
50	3	1				37
60	1					38
25	1					39
50	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	04/13/2017	End of 2016/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)	
414	3					1
60	1					2
756	3					3
795	3					4
675	3	1				5
40	2					6
40	1					7
40	1					8
65	2					9
50	2					10
50	2					11
50	2		23/12Kv Step-Down	4	5	12
65	2					13
6	1					14
19	3	1				15
50	2					16
200	1					17
31	3	1				18
25	1					19
1008	3					20
50	3	1				21
200	1					22
25	1					23
50	2					24
50	3	1				25
25	1					26
50	2					27
50	2					28
50	2					29
25	1					30
40	1					31
50	3	1				32
25	1					33
25	1					34
290	1					35
80	2					36
20	1					37
740	2					38
50	4	1				39
50	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	04/13/2017	End of 2016/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) (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.
110	4					1
40	1					2
25	2					3
30	1					4
25	1					5
50	2					6
50	2					7
48	2					8
40	1					9
50	2					10
25	1					11
2000	6	1	MbSp230-115/24/13/12	4	83	12
50	3	2				13
40	1					14
80	3	1				15
50	2	1				16
150	1					17
336	1					18
5	3					19
150	3	1				20
100	1					21
50	2					22
50	2					23
1186	7					24
20	3	1				25
50	2					26
400	2					27
180	2					28
30	1					29
50	2					30
50	3	1				31
50	2					32
600	2		Mb.Sp.(230/23kV)	1	25	33
50	3	1				34
300	1					35
25	1					36
50	2					37
50	2					38
100	4					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) 04/13/2017	Year/Period of Report End of 2016/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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
40	1					1
50	3	1				2
90	3					3
600	2					4
40	1					5
400	2					6
100	4					7
25	1					8
40	1					9
50	3	1				10
50	2					11
300	1					12
50	1					13
						14
						15
						16
						17
25	1					18
50	2					19
25	1					20
50	2					21
25	1					22
200	1					23
25	1					24
25	1					25
25	1					26
50	2					27
25	1					28
50	3	1				29
1084	8					30
40	1					31
50	3	1				32
25	1					33
25	1					34
9	1					35
25	1					36
75	3					37
600	2					38
25	1					39
25	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
25	1					2
50	2					3
40	1					4
50	3	1				5
50	2					6
50	3	1				7
50	2					8
50	2					9
20	3					10
6	1					11
150	1					12
25	1					13
65	2					14
30	3	1				15
25	1					16
25	1					17
400	2					18
50	3	1				19
25	1					20
50	2					21
15	3					22
25	1					23
25	1					24
25	1					25
990	3	1				26
600	2					27
50	3	1	12/23kV Step-Up	1	25	28
25	1					29
25	1					30
75	3					31
600	2					32
25	1					33
50	3	1				34
50	2					35
50	2					36
154	2					37
						38
						39
						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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
18312						1
24832						2
5						3
13537						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
						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	04/13/2017	End of 2016/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	40,692,830
3		Duke Energy Florida	various	1,829,211
4	Generation Services Provided by Affiliate	Duke Energy Carolinas	various	356,556,146
5		Duke Energy Florida	various	2,384,991
6	Other Goods and Services Provided by Affiliate	Duke Energy Carolinas	various	23,008,029
7		Piedmont Natural Gas	various	19,186,299
8	Transmission and Distribution Services Provided			
9	by Affiliate	Duke Energy Carolinas	various	26,122,547
10		Duke Energy Florida	various	2,589,400
11		Duke Energy Indiana	various	1,615,909
12		Duke Energy Ohio	various	1,207,965
13	Service Company Transactions	Duke Energy Business Services	various	462,171,327
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	3,645,058
22		Duke Energy Florida	various	2,288,199
23		Duke Energy Ohio	various	1,110,550
24		Duke Energy Indiana	various	866,052
25		Duke Energy Kentucky	various	341,455
26	DE Progress Provided Generation Services	Duke Energy Carolinas	various	42,400,564
27		Duke Energy Florida	various	2,225,415
28		Duke Energy Indiana	various	1,222,437
29	DE Progress Provided Other Goods and Services	Duke Energy Carolinas	various	3,016,520
30		Duke Energy Florida	various	1,400,951
31		Duke Energy Indiana	various	882,617
32	DE Progress Provided Transmission and			
33	Distribution Services	Duke Energy Carolinas	various	21,049,639
34		Duke Energy Florida	various	5,003,955
35		Duke Energy Indiana	various	1,832,942
36		Duke Energy Ohio	various	1,044,740
37	DE Progress Provided Service Company Transactions	Duke Energy Business Services	various	1,260,821
38				
39				
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

Schedule	Page No.

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