THIS FILING IS		
Item 1: ☒ 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 2018/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Duke Energy Progress, LLC	02 Year/Period of Report End of 2018/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 Shana Angers	06 Title of Contact Person Manager Accounting II
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* (980) 373-2532	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/12/2019

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 Dwight Leon Jacobs	03 Signature Dwight Leon Jacobs	04 Date Signed *(Mo, Da, Yr)* 04/12/2019
02 Title SVP, CAO, Tax and Controller		

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

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	04/12/2019	End of 2018/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.

Dwight Leon Jacobs
Senior Vice President, Chief Accounting Officer, Tax and Controller
550 South Tryon Street
Charlotte, NC 28202

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

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

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

Not applicable

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

Electric Power in the states of North Carolina and South Carolina

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

CONTROL OVER RESPONDENT

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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 Progess 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	Executive Vice President, Energy Solutions and	Douglas F. Esamann	625,950
2	President, Midwest & Florida Regions		
3			
4	Chief Executive Officer	Lynn J. Good	1,350,000
5			
6	Executive Vice President and Chief Operating Officer	Dhiaa M. Jamil	807,188
7			
8	Executive Vice President, External Affairs and Chief	Julia S. Janson	640,625
9	Legal Officer and Secretary through 10/31/2018		
10	Executive Vice President, External Affairs and Chief		640,625
11	Legal Officer, effective 11/01/2018		
12			
13	Executive Vice President, Customer and Delivery	Lloyd M. Yates	703,921
14	Operations and President, Carolinas Region		
15			
16	Executive Vice President, Administration and	Melissa Anderson	522,596
17	Chief Human Resources Officer		
18			
19	Senior Vice President, Chief Accounting Officer and	William E. Currens, Jr.	330,842
20	Controller, through 05/31/2018		
21			
22	President, North Carolina, Tax and Treasurer	Stephen Gerard De May	406,735
23	through 10/31/2018		
24			
25	Senior Vice President, Legal, Chief Ethics and	David Fountain	408,626
26	Compliance Officer and Corporate Secretary		
27	effective 11/01/2018		
28			
29	President, South Carolina	Kodwo Ghartey-Tagoe	341,505
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31	Senior Vice President, Chief Accounting Officer,	Dwight L. Jacobs	311,881
32	Tax and Controller, effective 06/01/2018		
33			
34	Senior Vice President, Corporate Development and	Karl Newlin	484,100
35	Treasurer, effective 11/01/2018		
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37	Executive Vice President and Chief Financial Officer	Steven Keith Young	710,325
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Douglas F. Esamann	550 South Tryon Street, Charlotte, NC 28202
2	Executive Vice President, Energy Solutions	
3	President , Midwest and Florida Regions	
4		
5	Lynn J. Good	550 South Tryon Street, Charlotte, NC 28202
6	Chief Executive Officer	
7		
8	Dhiaa M. Jamil	550 South Tryon Street, Charlotte, NC 28202
9	Executive Vice President	
10	Chief Operating Officer	
11		
12	Julia S. Janson	550 South Tryon Street, Charlotte, NC 28202
13	Executive Vice President, External Affairs	
14	Chief Legal Officer	
15		
16	Lloyd M. Yates	550 South Tryon Street, Charlotte, NC 28202
17	Executive Vice President, Customer and Delivery Operations	
18	President, Carolinas Region	
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Joint Open Access Transmission Tariff (OATT)	ER17-2567
2	RS 172	ER17-1839
3	RS 180	ER17-1839
4	RS 182	ER18-485
5	RS 184	ER19-694
6	RS 197	ER18-207
7	RS 200	ER17-1557
8	RS 210	ER18-253
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	20180515-5329	05/15/2018	ER09-1165	2018 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	04/12/2019	End of 2018/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 Pension & Benefits	(c)	29
3	200	Intangible Amortization Reserve	(c)	62-67
4	205	Intangible Plant	(g)	5
5	205	Production Plant	(g)	46
6	207	Transmission Plant	(g)	58
7	207	General Plant	(g)	98-99
8	219	General Depr. Reserve	(c)	28
9	219	Production Depr. Reserve	(c)	20-24
10	232	SFAS 158 Regulatory Assets	(f)	3
11	263	Other Taxes - FICA/Unemployment/Social Security	(i)	3 & 5
12	263	Other Taxes - Real & Personal Property	(i)	10 & 19
13	321	Total Production Expense	(b)	80
14	323	Total Admin & General Expenses	(b)	197
15	323	Property Insurance	(b)	185
16	327	Purchase Power Demand Charges	(j)	Total
17	335	Industry Dues, R&D,C-V Nuc Pwr Assoc	(b)	1-3
18	336	Intangible Amortization	(f)	1
19	336	Production Depreciation Expenses	(b)	2-6
20	336	General Depr. Expenses	(b)	10
21	354	A&G Labor	(b)	27
22	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	04/12/2019	End of 2018/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. None

6. See Notes to Financial Statements, Note 5, "Debt and Credit Facilities"

7. None

8. During the fourth quarter of 2018, no changes were made.

   During the third quarter of 2018, non-represented DEP craft employees were granted a general wage increase of 3% that totaled $4,300,430 in annualized costs, impacting 1,796 employees. (This excludes promotions, demotions, job reclassification, etc.).

   During the second quarter of 2018, there were no large scale wage changes for Duke Energy Progress.

   During the first quarter of 2018, Duke Energy Progress granted an approximate 3% merit increase which resulted in $8,783,181, impacting 3,198 employees.

9. See Notes to Financial Statements, Note 3, "Regulatory Matters" and Note 4,"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 2018.

    The officer and director appointments and resignations that occurred during the fourth quarter 2018 are as follows:

Appointments Effective November 2018

Melody Birmingham-Byrd, Senior Vice President and Chief Procurement Officer

Donald E. Broadhurst, Vice President Operations-Customer Delivery

Swati V. Daji, Senior Vice President, Customer Solutions

Joni Y. Davis, Vice President, Chief Diversity and Inclusion Officer

Steven Gerard De May, President, North Carolina

David B. Fountain, Senior Vice President, Legal, Chief Ethics and Compliance Officer and Secretary

Emily G. Henson, Vice President Operations-Customer Delivery

Rufus Stanley Jackson, Vice President Operations-Customer Delivery

Julia S. Janson, Executive Vice President, External Affairs and Chief Legal Officer

Jackie Joyner, Vice President Operations-Customer Delivery

Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer

L. Stanford Sherrill, Jr., Vice President, Talent Acquisition and Workforce Development

Sandra S. Wyckoff, Vice President, Ethics and Compliance

Appointments Effective October 2018

Scott L. Batson, Regional Senior Vice President, Customer Delivery

Steven D. Capps, Senior Vice President, Nuclear Operations (SC)

Larry E. Hatcher, Senior Vice President, Customer Delivery Governance, Programs and Support

Mia S. Haynes, Vice President, Customer Care

Kim Maza, Vice President, Nuclear Corporate Operations

RESIGNATIONS Effective December 2018

Caren B. Anders, Vice President, Operations Support

Christopher B. Heck, Vice President and Chief Information Officer

John F. Smith III, Senior Vice President, Distribution Grid Performance and Contractor Operations

RESIGNATIONS Effective November 2018

Swati V. Daji, Senior Vice President, Chief Procurement Officer

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

Stephen Gerard De May, Treasurer and Senior Vice President, Tax

David B. Fountain, President, North Carolina

Emily G. Henson, Vice President, Distribution Construction and Maintenance - Carolinas West

Rufus Stanley Jackson, Vice President, Distribution Construction and Maintenance - Carolinas East

Julia S. Janson, Executive Vice President, External Affairs, Chief Legal Officer and Secretary

Karl W. Newlin, Senior Vice President, Corporate Development

L. Stanford Sherrill,Jr., Vice President, Workforce Development, Diversity & Inclusion

Alexander J. Weintraub, Senior Vice President, Customer Solutions

Sandra S. Wyckoff, Vice President and Chief Ethics and Compliance Officer

RESIGNATIONS Effective October 2018

Scott L. Batson, Senior Vice President, Nuclear Operations (SC)

Steven D. Capps, Senior Vice President, Nuclear Corporate

Kim Maza, Vice President, Nuclear Corporate Governance & Oversight

The officer and director appointments and resignations that occurred during the third quarter 2018 are as follows:

Appointments Effective September 2018
Dennis P. Gilbert, Jr. Vice President and Chief Information Security Officer

Appointments Effective August 2018
Rodney E. Gaddy   Senior Vice President, Administrative Services

Appointments Effective July 2018
Clark S. Gillespy   Senior Vice President, Economic Development
Brian R. Weisker   Vice President, Natural Gas Operational Excellence

RESIGNATIONS Effective September 2018
Lisa M. Marcuz   Vice President, Talent Management

RESIGNATIONS Effective August 2018
Rodney E. Gaddy   Vice President, Administrative Services

David J. Maxon   Senior Vice President, Distribution Construction and Maintenance

RESIGNATIONS Effective July 2018
Larry E. Hatcher   Vice President, Natural Gas Operational Excellence

Brian R. Weisker   Vice President, Coal Combustion Products Operations and Maintenance

The officer and director appointments and resignations that occurred during the second quarter 2018 are as follows:

Appointments Effective June 2018
Donna T. Council   Vice President, HR Strategic Business Solutions

William E. Currens Jr. Senior Vice President, Financial Planning and Analysis

James P. Henning   Senior Vice President, Customer Services

Dwight L. Jacobs   Senior Vice President, Chief Accounting Officer and Controller

Karl W. Newlin   Senior Vice President, Corporate Development

Deborah T. Patton   HR Director, Employee Relations

Stanford L. Sherrill, Jr. Vice President, Workforce Development, Diversity & Inclusion

Harry K. Sideris   Senior Vice President and Chief Distributions Officer

RESIGNATIONS Effective June 2018
Jeffrey A. Corbett Senior Vice President, Distribution Engineering and Technical Customer Relations

Donna Council Vice President, Human Resources Business Partners

William E. Currens Jr. Senior Vice President, Chief Accounting Officer and Controller

Michael A. Lewis Senior Vice President and Chief Distribution Officer

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

Catherine S. Stempien Senior Vice President, Corporate Development

Charles R. Whitlock Senior Vice President, Strategic Growth Initiatives

RESIGNATIONS Effective May 2018

Michael R. Delowery Vice President, Project Management and Construction

RESIGNATIONS Effective April 2018

Gayle S. Lanier Senior Vice President, Customer Services

The officer and director appointments and resignations that occurred during the first quarter 2018 are as follows:

Appointments Effective March 2018

Larry E. Hatcher Vice President, Natural Gas Operational Excellence

Michael S. Hendershott Assistant Treasurer

RESIGNATIONS Effective March 2018

Kris C. Duffy Assistant Treasurer

Larry E. Hatcher Vice President, Environmental

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	29,287,780,541	27,640,413,426
3	Construction Work in Progress (107)	200-201	1,665,669,162	1,422,282,356
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		30,953,449,703	29,062,695,782
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	12,297,905,722	11,818,924,780
6	Net Utility Plant (Enter Total of line 4 less 5)		18,655,543,981	17,243,771,002
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	325,126,686	372,875,189
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		819,511,288	842,377,497
10	Spent Nuclear Fuel (120.4)		417,494,987	344,303,937
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	860,218,709	830,851,022
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		701,914,252	728,705,601
14	Net Utility Plant (Enter Total of lines 6 and 13)		19,357,458,233	17,972,476,603
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		37,914,817	36,739,137
19	(Less) Accum. Prov. for Depr. and Amort. (122)		16,451,815	12,137,682
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	27,726,543	20,150,772
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)		42,286,541	41,622,284
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,776,861,603	2,872,581,764
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)		449,408	551,380
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,868,787,097	2,959,507,655
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		-2,531,695	16,603,425
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		432,169,365	344,026,988
41	Other Accounts Receivable (143)		68,114,949	120,073,290
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,357,981	6,458,355
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		110,020,232	57,088,400
45	Fuel Stock (151)	227	220,024,307	242,760,869
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	700,609,217	739,132,797
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	182,270	134,782
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	122,682,758	109,087,159

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	33,384,627	35,393,695
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)		90,940,901	72,816,399
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		94,136	326,380
61	Accrued Utility Revenues (173)		129,690,282	143,197,755
62	Miscellaneous Current and Accrued Assets (174)		10,148,021	563,130
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		761,715	2,172,282
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		449,408	551,380
67	Total Current and Accrued Assets (Lines 34 through 66)		1,908,483,696	1,876,367,616
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		43,142,470	42,389,406
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	153,655,703	183,051,153
72	Other Regulatory Assets (182.3)	232	4,265,025,648	3,419,931,113
73	Prelim. Survey and Investigation Charges (Electric) (183)		8,201,316	5,025,345
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)		6,938,847	5,088,642
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	544,504,452	394,301,626
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)		4,579,195	5,609,529
82	Accumulated Deferred Income Taxes (190)	234	1,864,956,280	1,775,392,682
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		6,891,003,911	5,830,789,496
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		31,025,732,937	28,639,141,370

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	2,784,376,572	2,784,376,571
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	5,933,703,999	5,449,057,894
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-277,197,059	-284,587,146
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)	-149,270	-180,809
16	Total Proprietary Capital (lines 2 through 15)		8,440,734,242	7,948,666,510
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,623,485,000	6,823,485,000
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	350,000,000	300,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		15,293,974	16,187,768
24	Total Long-Term Debt (lines 18 through 23)		8,108,191,026	7,257,297,232
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		133,281,241	136,548,646
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		6,874,145	7,952,093
29	Accumulated Provision for Pensions and Benefits (228.3)		223,622,886	232,708,439
30	Accumulated Miscellaneous Operating Provisions (228.4)		17,201,995	18,257,902
31	Accumulated Provision for Rate Refunds (229)		123,351,482	0
32	Long-Term Portion of Derivative Instrument Liabilities		4,886,654	5,556,146
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		3,728,239	3,397,097
34	Asset Retirement Obligations (230)		4,819,759,728	4,673,454,040
35	Total Other Noncurrent Liabilities (lines 26 through 34)		5,332,706,370	5,077,874,363
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		723,822,837	404,314,214
39	Notes Payable to Associated Companies (233)		293,651,000	239,986,000
40	Accounts Payable to Associated Companies (234)		271,157,048	172,996,605
41	Customer Deposits (235)		137,270,708	129,255,428
42	Taxes Accrued (236)	262-263	59,278,673	71,459,237
43	Interest Accrued (237)		116,877,826	102,815,253
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)		7,936,232	5,530,414
48	Miscellaneous Current and Accrued Liabilities (242)		227,936,822	207,717,863
49	Obligations Under Capital Leases-Current (243)		3,267,405	2,861,742
50	Derivative Instrument Liabilities (244)		16,120,103	6,119,276
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		4,886,654	5,556,146
52	Derivative Instrument Liabilities - Hedges (245)		6,466,582	10,073,679
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		3,728,239	3,397,097
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,855,170,343	1,344,176,468
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		22,775,276	25,775,971
57	Accumulated Deferred Investment Tax Credits (255)	266-267	142,161,990	143,330,909
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	19,844,812	25,789,789
60	Other Regulatory Liabilities (254)	278	3,120,844,123	3,158,363,633
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		2,695,677,136	2,555,356,409
64	Accum. Deferred Income Taxes-Other (283)		1,287,627,619	1,102,510,086
65	Total Deferred Credits (lines 56 through 64)		7,288,930,956	7,011,126,797
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		31,025,732,937	28,639,141,370

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	5,682,421,296	5,125,684,512		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,842,529,953	2,492,514,198		
5	Maintenance Expenses (402)	320-323	524,022,724	472,231,323		
6	Depreciation Expense (403)	336-337	746,423,281	633,577,367		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	42,090,299	37,989,554		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	12,758,733	12,758,733		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		29,040,562	31,048,241		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		365,010,904	284,278,998		
13	(Less) Regulatory Credits (407.4)		135,488,252	237,323,828		
14	Taxes Other Than Income Taxes (408.1)	262-263	153,362,211	153,535,056		
15	Income Taxes - Federal (409.1)	262-263	-66,292,964	-91,946,206		
16	- Other (409.1)	262-263	-3,938,471	2,562,304		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	843,871,407	1,186,870,107		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	623,018,430	760,715,065		
19	Investment Tax Credit Adj. - Net (411.4)	266	-3,355,660	-3,380,372		
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)		165,404	378,052		
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)		4,726,850,893	4,213,622,358		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		955,570,403	912,062,154		

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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
5,682,421,296	5,125,684,512					2
						3
2,842,529,953	2,492,514,198					4
524,022,724	472,231,323					5
746,423,281	633,577,367					6
						7
42,090,299	37,989,554					8
12,758,733	12,758,733					9
29,040,562	31,048,241					10
						11
365,010,904	284,278,998					12
135,488,252	237,323,828					13
153,362,211	153,535,056					14
-66,292,964	-91,946,206					15
-3,938,471	2,562,304					16
843,871,407	1,186,870,107					17
623,018,430	760,715,065					18
-3,355,660	-3,380,372					19
						20
						21
165,404	378,052					22
						23
						24
4,726,850,893	4,213,622,358					25
955,570,403	912,062,154					26

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)		955,570,403	912,062,154		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		-86,843	-7		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		29,121			
33	Revenues From Nonutility Operations (417)		33,624,375	31,097,036		
34	(Less) Expenses of Nonutility Operations (417.1)		23,752,601	24,078,603		
35	Nonoperating Rental Income (418)		-633,026	-553,739		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	7,394,428	1,789,130		
37	Interest and Dividend Income (419)		1,387,385	1,693,291		
38	Allowance for Other Funds Used During Construction (419.1)		56,812,523	47,441,028		
39	Miscellaneous Nonoperating Income (421)		9,121,726	21,335,420		
40	Gain on Disposition of Property (421.1)		1,296,268	1,291,897		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		85,135,114	80,015,453		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		383,831	1,636,650		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,334,051	2,301,970		
46	Life Insurance (426.2)		-1,642,235	-489,388		
47	Penalties (426.3)		1,878,534	389,218		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,159,976	2,702,960		
49	Other Deductions (426.5)		34,603,501	25,332,275		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		41,717,658	31,873,685		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,961,060	2,072,971		
53	Income Taxes-Federal (409.2)	262-263	-5,144,014	-2,417,291		
54	Income Taxes-Other (409.2)	262-263	-645,223	-204,716		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	28,378,574	11,814,863		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	9,796,689	51,014,160		
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)		14,753,708	-39,748,333		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		28,663,748	87,890,101		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		316,675,114	285,462,085		
63	Amort. of Debt Disc. and Expense (428)		5,814,338	5,054,777		
64	Amortization of Loss on Reaquired Debt (428.1)		1,030,335	1,033,597		
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)		8,649,424	5,557,512		
68	Other Interest Expense (431)		10,728,365	8,404,622		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		25,699,616	20,958,187		
70	Net Interest Charges (Total of lines 62 thru 69)		317,197,960	284,554,406		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		667,036,191	715,397,849		
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)		667,036,191	715,397,849		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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		5,443,461,024	4,855,687,557
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Transfer to Unappropriated RE (Account 216.1)		4,341	41,373
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		4,341	41,373
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		659,641,763	713,608,719
17	Appropriations of Retained Earnings (Acct. 436)			
18	Hydro Project Reserve Amortization	215.1	-758,845	(876,625)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-758,845	(876,625)
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		-175,000,000	(125,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-175,000,000	(125,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		5,927,348,283	5,443,461,024
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)		6,355,716	5,596,870
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		6,355,716	5,596,870
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		5,933,703,999	5,449,057,894
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-284,587,146	(286,334,903)
50	Equity in Earnings for Year (Credit) (Account 418.1)		7,394,428	1,789,130
51	(Less) Dividends Received (Debit)			
52	Transfer from Unappropriated RE (Account 216)		-4,341	(41,373)
53	Balance-End of Year (Total lines 49 thru 52)		-277,197,059	(284,587,146)

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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)	667,036,191	715,397,849
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	746,423,281	633,577,367
5	Amortization and Accretion	268,694,905	326,697,066
6	Net (Increase) Decrease in Mark-to-Market Hedging Transactions	15,075,058	-3,535,981
7	Contribution to Company-Sponsored Pension Plans	-24,816,258	-1,287
8	Deferred Income Taxes (Net)	239,434,862	386,955,745
9	Investment Tax Credit Adjustment (Net)	-3,355,660	-3,380,372
10	Net (Increase) Decrease in Receivables	-74,311,123	-114,247,670
11	Net (Increase) Decrease in Inventory	63,221,722	58,550,783
12	Net (Increase) Decrease in Allowances Inventory	-13,436,486	-33,022,444
13	Net Increase (Decrease) in Payables and Accrued Expenses	407,650,725	-322,389,286
14	Net (Increase) Decrease in Other Regulatory Assets	-553,018,299	-37,029,778
15	Net Increase (Decrease) in Other Regulatory Liabilities	133,693,600	-97,693,807
16	(Less) Allowance for Other Funds Used During Construction	56,812,523	47,441,028
17	(Less) Undistributed Earnings from Subsidiary Companies	7,394,428	1,789,130
18	Other (provide details in footnote):	-459,234,570	-249,059,700
19	Accrued Pension and Other Post-Retirement Benefit Costs Adj to NI	14,543,544	-19,705,406
20	Provision for Rate Refund	123,351,482	
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,486,746,023	1,191,882,921
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,964,141,297	-1,597,038,770
27	Gross Additions to Nuclear Fuel	-175,835,579	-162,722,373
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-1,175,679	-494,282
30	(Less) Allowance for Other Funds Used During Construction	-56,812,523	-47,441,028
31	Other (provide details in footnote):		
32	Additions from Affiliated Companies		-4,361,149
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,084,340,032	-1,717,175,546
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		52
38	Cost of Removal, net of Salvage	-114,416,778	-52,165,993
39	Investments in and Advances to Assoc. and Subsidiary Companies	-181,341	164,745,561
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,235,790,237	-1,249,133,802
45	Proceeds from Sales of Investment Securities (a)	1,210,064,019	1,211,437,038

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	-1,346,430	1,580,023
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-2,226,010,799	-1,640,712,667
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	849,884,000	817,075,186
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	849,884,000	817,075,186
71	Other Financing Activities (provide details in footnote)	-5,557,602	-6,659,009
72	Payments for Retirement of:		
73	Long-term Debt (b)	-2,861,742	-470,317,382
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	53,665,000	239,986,000
78	Net Decrease in Short-Term Debt (c)		
79	Dividends ot Parent	-175,000,000	-125,000,000
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)	720,129,656	455,084,795
84	Supplemental Disclosures		
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-19,135,120	6,255,049
87			
88	Cash and Cash Equivalents at Beginning of Period	16,603,425	10,348,376
89			
90	Cash and Cash Equivalents at End of period	-2,531,695	16,603,425

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

Change in other noncurrent assets	$ (240,624,583)
Asset retirement obligation liabilities settled	(195,197,365)
Change in prepaid and other current assets	(28,016,303)
Change in deferred credits and other long-term liabilities	(16,567,223)
Payment of charitable contributions related to Piedmont merger commitments	(7,489,687)
Gain on sale of assets	(4,818,526)
Equity method investment income	147,797
Impairment	33,331,320
	$ (459,234,570)

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

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

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

Death proceeds from COLI and Rabbi Trust $ (1,346,430)

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

Death proceeds from COLI and Rabbi Trust $ 1,580,023

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

Primarily unamortized debt expenses associated with:

Issuances of LT Debt	$ (4,812,993)
Master Credit Facility Fees	(774,609)

$ (5,557,602)

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

Primarily unamortized debt expenses associated with:

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

Schedule Page: 120 Line No.: 84 Column: b

Significant noncash transactions:

Accrued capital expenditures $ 230,352,719

Supplemental Disclosures:

Cash paid for interest, net of amount capitalized $ 303,219,943

Cash paid for income taxes, net $ 111,830,662

Schedule Page: 120 Line No.: 84 Column: c

Significant noncash transactions:

Accrued capital expenditures $ 191,130,689

Supplemental Disclosures:

Cash paid for interest, net of amount capitalized $ 291,420,459

Cash paid for income taxes, net $ 58,986,643

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

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

Cash (131) $ 16,603,425

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

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

Cash (131) $ 10,348,376

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

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

Cash (131) $ (2,531,695)

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

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

Cash (131) $ 16,603,425

NOTES TO FINANCIAL STATEMENTS

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

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

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

(a) GAAP requires that public business enterprises report certain information about operating segments in complete sets of financial statements of the enterprise and certain information about their products and services, which are not required for FERC reporting purposes.
(b) GAAP requires that majority-owned subsidiaries be consolidated for financial reporting purposes. FERC requires that majority-owned subsidiaries be separately reported as Investment in Subsidiary Companies unless an appropriate waiver has been granted by the FERC.
(c) 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.
(d) 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.
(e) 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.
(f) 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.
(g) 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.
(h) 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.
(i) GAAP requires that regulated assets that are abandoned or retired early, including the cost of the asset and its associated accumulated depreciation, be reclassified to a separate regulatory asset on the Balance Sheet. For FERC reporting purposes, those assets which have been abandoned but are still operating are maintained in their original balance sheet accounts.
(j) GAAP requires that the current portion of Asset Retirement Obligations be reported as current liabilities on the Balance Sheet. For FERC reporting purposes, these liabilities are not reported separately and are reflected as Asset Retirement Obligations within the Other Noncurrent Liabilities section of the Balance Sheet
(k) With the adoption of Accounting Standards Update (ASU) No. 2017-17 January 1, 2018, GAAP requires that the service cost related to pensions and post-retirement benefits other than pensions (PBOP) be reported with other compensation costs arising from services rendered by employees during the period be included in a subtotal of income from operations on the income statement, while non-service cost components are to be presented in the income statement separately outside a subtotal of income from operations. Only the service cost component may be eligible for capitalization if all other capitalization criteria are met. For FERC reporting purposes, costs related to pensions and PBOP will be included in the Net Utility Operating Income of the income statement. Duke has made a non-revocable election to capitalize only the service cost component of pension and PBOP costs, upon implementing ASU No. 2017-07. This change is not expected to have a material impact on the financial statements

The Combined Notes To Consolidated Financial Statements below are as published for the year ended December 31, 2018 Form 10-K (includes Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Duke Energy Florida, LLC, Duke Energy Ohio, Inc., Duke Energy Indiana, LLC and Piedmont Natural Gas Company, Inc.) filed on February 28, 2019. See “Index to the Combined Notes to Consolidated Financial Statements” for a listing of applicable notes for Duke Energy Progress, LLC.

Management has evaluated the impact of events occurring after December 31, 2018 up to February 28, 2019, the date that Duke Energy Corporation’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 12, 2019. These financial statements include all necessary adjustments and disclosures resulting from these evaluations including the following disclosure. On April 1, 2019, the NCDEQ issued a closure determination requiring Duke Energy Carolinas and Duke Energy Progress to excavate all remaining coal ash impoundments at facilities in North Carolina. Duke Energy estimates the cost to close these impoundments by excavation will be approximately $4 billion to $5 billion more than the current project cost estimate of $5.6 billion in the aggregate for the closure for all Duke Energy Carolinas and Duke Energy Progress impoundments. Excavation would likely extend beyond the required federal and state deadlines for impoundment closure. Duke Energy Carolinas and Duke Energy Progress intend to seek recovery of all costs through the ratemaking process consistent with previous proceedings. Duke Energy is still evaluating the closure determination from the NCDEQ and cannot predict the outcome of this matter.

DEP FERC Federal Tax Reform Disclosure

In December 2017, Duke Energy Progress re-measured its deferred tax assets and liabilities to the new federal corporate income tax rate of 21%. The result of this re-measurement was a reduction in the net deferred tax liability of approximately $1.5 billion. Based on our estimate of the amount of excess deferred income taxes (EDIT) that would be used to reduce future customer rates, we recorded an increase in regulatory liabilities of approximately $1.8 billion. The additional $415 million in regulatory liabilities was required to reflect the future revenue reduction required to return $1.4 billion of previously collected income taxes to customers. We also recorded a $415 million deferred tax asset related to the $1.4 billion regulatory liability. The accounts that were debited and (credited) in the 2017 re-measurement of deferred income taxes are reflected below (in millions):

	254	**190**	**282**	**283**	**411.2**	**182.3/253/254**
EDIT	$ (1,376)	$ (765)	$ 1,528	$ 704	$ (39)	$ (52)
Gross ups	$ (415)	$ 415				
Total	$ (1,791)	$ (350)	$ 1,528	$ 704	$ (39)	$ (52)

	NC Retail	**SC Retail**	**Wholesale-Generation/Production**	**Wholesale-Transmission**	**Total**
EDIT Detail by Customer	$(881)	$(157)	$(91)	$(247)	$(1,376)

In December 2018, Duke Energy Progress recorded adjustments to accumulated deferred income taxes (ADIT) and EDIT after filing its 2017 tax return. As of December 2018, the cumulative re-measurement is shown below (in millions):

	254	**190**	**282**	**283**	**411.2**	**182.3/253/254**
EDIT	$ (1,412)	$ (772)	$ 1,548	$ 709	$ (21)	$ (52)
Gross ups	$ (426)	$ 426				
Total	$ (1,838)	$ (346)	$ 1,548	$ 709	$ (21)	$ (52)

	NC Retail	**SC Retail**	**Wholesale-Generation/Production**	**Wholesale-Transmission**	**Total**
EDIT Detail by Customer	$(904)	$(161)	$(93)	$(254)	$(1,412)

The amount of excess deferred income taxes that is considered protected and unprotected as of December 31, 2018 and 2017 is reflected below (in millions):

EDIT Category	**12/31/2018**	**12/31/2017**
Protected:		
NC Retail	$ (632)	$ (700)
SC Retail	$ (113)	$ (125)
Production FERC	$ (65)	$ (72)
Transmission FERC	$ (180)	$ (196)
Unprotected:		
NC Retail	$ (272)	$(181)
SC Retail	$ (48)	$ (32)
Production FERC	$ (28)	$ (19)
Transmission FERC	$ (74)	$ (51)
Total	**$ 1,412**	**$ (1,376)**

Duke Energy Progress has not received a regulatory order from North Carolina Utilities Commission or the South Carolina Public Service Commission regarding how customer rates should be reduced for excess deferred income taxes. The reduction in the excess deferred income tax regulatory liability will offset against account 411.1, the account to which the original re-measurement of deferred income taxes was recorded in December 2017. The estimated amortization period based on regulatory orders, and the account that the amortization will be reported in, is reflected below.

EDIT Category by Jurisdiction	**Amortization Period**
411.1	
Protected	In accordance with ARAM, which is generally between 25 and 50 years
Unprotected:	
NC Retail	Evaluating rate case for 2019
SC Retail	Rate case in process
Production FERC	10 years straight line starting 1/1/2019
Transmission FERC	Pending outcome of FERC NOPR

In the table above, ARAM refers to the average rate assumption method.

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**	**26**
Duke Energy	•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•	•	•	•	•	•	•	•	•
Duke Energy Carolinas	•		•	•	•	•	•	•	•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Progress Energy	•		•	•	•	•	•		•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Progress	•		•	•	•	•			•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Florida	•		•	•	•	•			•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Ohio	•		•	•	•	•		•	•	•	•		•	•		•	•	•		•	•	•	•	•	•	•
Duke Energy Indiana	•		•	•	•	•		•	•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Piedmont	•	•	•	•	•	•			•	•	•	•	•	•		•		•		•	•	•	•	•	•	•

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Consolidation

Duke Energy is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the FERC and other regulatory agencies listed below. Duke Energy operates in the U.S. primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also subsidiary registrants, including Duke Energy Carolinas; Progress Energy; Duke Energy Progress; Duke Energy Florida; Duke Energy Ohio; Duke Energy Indiana and Piedmont. When discussing Duke Energy’s consolidated financial information, it necessarily includes the results of its separate Subsidiary Registrants, which along with Duke Energy, are collectively referred to as the Duke Energy Registrants.

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

In December 2016, Duke Energy completed an exit of the Latin American market to focus on its domestic regulated business, which was further bolstered by the acquisition of Piedmont. The sale of the International Energy business segment, excluding an equity method investment in NMC, was completed through two transactions including a sale of assets in Brazil to CTG and a sale of Duke Energy's remaining Latin American assets in Peru, Chile, Ecuador, Guatemala, El Salvador and Argentina to I Squared (collectively, the International Disposal Group). See Note 2 for additional information on the sale of International Energy.

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

These Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of the Duke Energy Registrants and subsidiaries or VIEs where the respective Duke Energy Registrants have control. See Note 17 for additional information on VIEs. These Consolidated Financial Statements also reflect the Duke Energy Registrants’ proportionate share of certain jointly owned generation and transmission facilities. See Note 8 for additional information on joint ownership. Substantially all of the Subsidiary Registrants' operations qualify for regulatory accounting.

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

Progress Energy is a public utility holding company, which conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida. Progress Energy is subject to regulation by FERC and other regulatory agencies listed below.

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

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

Duke Energy Ohio is a regulated public utility primarily engaged in the transmission and distribution of electricity in portions of Ohio and Kentucky, the generation and sale of electricity in portions of Kentucky and the transportation and sale of natural gas in portions of Ohio and Kentucky. Duke Energy Ohio conducts competitive auctions for retail electricity supply in Ohio whereby the energy price is recovered from retail customers and recorded in Operating Revenues on the Consolidated Statements of Operations and Comprehensive Income. Operations in Kentucky are conducted through its wholly owned subsidiary, Duke Energy Kentucky. References herein to Duke Energy Ohio collectively include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the PUCO, KPSC and FERC.

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 IURC and FERC.

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

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

Other Current Assets and Liabilities

The following table provides a description of amounts included in Other within Current Assets or Current Liabilities that exceed 5 percent of total Current Assets or Current Liabilities on the Duke Energy Registrants' Consolidated Balance Sheets at either December 31, 2018, or 2017.

		December 31,	
(in millions)	**Location**	**2018**	**2017**
Duke Energy			
Income taxes receivable	Current Assets	**$ 729**	$ 330
Accrued compensation	Current Liabilities	**793**	757
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 251**	$ 252
Progress Energy			
Income taxes receivable	Current Assets	**$ 66**	$ 278
Customer deposits	Current Liabilities	**345**	338
Duke Energy Progress			
Customer deposits	Current Liabilities	**$ 137**	$ 129
Accrued compensation	Current Liabilities	**130**	132
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 208**	$ 208
Other accrued liabilities	Current Liabilities	**85**	16
Duke Energy Ohio			
Income taxes receivable	Current Assets	**$ 13**	$ 36
Customer deposits	Current Liabilities	**44**	46
Duke Energy Indiana			
Customer deposits	Current Liabilities	**$ 47**	$ 45
Piedmont			
Income taxes receivable	Current Assets	**$ 11**	$ 43

Discontinued Operations

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

Amounts Attributable to Controlling Interests

For the years ended December 31, 2018, and 2017, the Income (Loss) From Discontinued Operations, net of tax on Duke Energy's Consolidated Statements of Operations is entirely attributable to controlling interest. For the year ended December 31, 2016, $18 million of net income is attributable to noncontrolling interests, which consisted of $7 million included in Income from Continuing Operations and $11 million included in Income (Loss) From Discontinued Operations, net of tax on Duke Energy's Consolidated Statement of Operations.

Significant Accounting Policies

Use of Estimates

In preparing financial statements that conform to GAAP, 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. For example, if a cost cap is set for a plant still under construction, the amount of the disallowance is a result of a judgment as to the ultimate cost of the plant. These disallowances can require judgments on allowed future rate recovery.

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

The Duke Energy Registrants utilize cost-tracking mechanisms, commonly referred to as fuel adjustment clauses or PGA clauses. 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, Cash Equivalents and Restricted Cash

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents. Duke Energy, Progress Energy and Duke Energy Florida have restricted cash balances related primarily to collateral assets, escrow deposits and VIEs. See Note 17 for additional information. Restricted cash amounts are included in Other within Current Assets and Other Noncurrent Assets on the Consolidated Balance Sheets. The following table presents the components of cash, cash equivalents and restricted cash included in the Consolidated Balance Sheets.

	December 31, 2018			December 31, 2017		
	Duke Energy	**Progress Energy**	**Duke Energy Florida**	**Duke Energy**	**Progress Energy**	**Duke Energy Florida**
Current Assets						
Cash and cash equivalents	**$ 442**	**$ 67**	**$ 36**	$ 358	$ 40	$ 13
Other	**141**	**39**	**39**	138	40	40
Other Noncurrent Assets						
Other	**8**	**6**	**—**	9	7	—
Total cash, cash equivalents and restricted cash	**$ 591**	**$ 112**	**$ 75**	$ 505	$ 87	$ 53

Inventory

Inventory is used for operations and is recorded primarily using the average cost method. Inventory related to regulated operations is valued at historical cost. Inventory related to nonregulated operations is valued at the lower of cost or market. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to property, plant and equipment when installed. Inventory, including excess or obsolete inventory, is written-down to the lower of cost or market value. Once inventory has been written-down, it creates a new cost basis for the inventory that is not subsequently written-up. Provisions for inventory write-offs were not material at December 31, 2018, and 2017. The components of inventory are presented in the tables below.

	December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Materials and supplies	**$ 2,238**	**$ 731**	**$ 1,049**	**$ 734**	**$ 315**	**$ 84**	**$ 312**	**$ 2**
Coal	**491**	**175**	**192**	**106**	**86**	**14**	**109**	**—**
Natural gas, oil and other	**355**	**42**	**218**	**114**	**103**	**28**	**1**	**68**
Total inventory	**$ 3,084**	**$ 948**	**$ 1,459**	**$ 954**	**$ 504**	**$ 126**	**$ 422**	**$ 70**

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

Investments in Debt and Equity Securities

The Duke Energy Registrants classify investments in equity securities as FV-NI and investments in debt securities as AFS. Both categories are recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on securities classified as FV-NI are reported through net income. Unrealized gains and losses for debt securities classified as AFS are included in AOCI until realized, except OTTIs that are included in earnings immediately. At the time gains and losses for debt securities are realized, they are reported through net income. For certain investments of regulated operations, such as substantially all of the NDTF, realized and unrealized gains and losses (including any OTTIs) on debt securities are recorded as a regulatory asset or liability. 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, Duke Energy Ohio and Piedmont perform annual goodwill impairment tests as of August 31 each year at the reporting unit level, which is determined to be a business segment or one level below. Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont update these tests between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 11 for further information.

Intangible Assets

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

Emission allowances permit the holder of the allowance to emit certain gaseous byproducts of fossil fuel combustion, including SO_2 and NO_X. Allowances are issued by the 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.

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

Long-Lived Asset Impairments

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

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

Equity Method Investment Impairments

Investments in affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method. Equity method investments are assessed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. If the decline in value is considered to be other than temporary, the investment is written down to its estimated fair value, which establishes a new cost basis in the investment.

Impairment assessments use a discounted cash flow income approach and include consideration of the severity and duration of any decline in the fair value of the investments. The estimated cash flows may be based on alternative expected outcomes that are probability weighted. Key inputs that involve estimates and significant management judgment include cash flow projections, selection of a discount rate, probability weighting of potential outcomes, and whether any decline in value is considered temporary.

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 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,		
	2018	**2017**	**2016**
Duke Energy	**3.0%**	2.8%	2.8%
Duke Energy Carolinas	**2.8%**	2.8%	2.8%
Progress Energy	**2.9%**	2.6%	2.7%
Duke Energy Progress	**2.9%**	2.6%	2.6%
Duke Energy Florida	**3.0%**	2.8%	2.8%
Duke Energy Ohio	**2.8%**	2.8%	2.6%
Duke Energy Indiana	**3.3%**	3.0%	3.1%
Piedmont[(a)]	**2.5%**	2.3%	

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

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

When the Duke Energy Registrants sell entire regulated operating units, or retire or sell nonregulated properties, the original cost and accumulated depreciation and amortization balances are removed from Property, Plant and Equipment on the Consolidated Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body. See Note 10 for additional information.

Nuclear Fuel

Nuclear fuel is classified as Property, Plant and Equipment 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 ETR when capitalized and increases the ETR when depreciated or amortized. See Note 23 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

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 probable of recovery.

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 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 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

Duke Energy recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred. See Note 18 for further information.

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 NPNS exception, are recorded on the Consolidated Balance Sheets at fair value. Qualifying derivative instruments may be designated as either cash flow hedges or fair value hedges. Other derivative instruments (undesignated contracts) either have not been designated or do not qualify as hedges. The effective portion of the change in the fair value of cash flow hedges is recorded in AOCI. The effective portion of the change in the fair value of a fair value hedge is offset in net income by changes in the hedged item. For activity subject to regulatory accounting, gains and losses on derivative contracts are reflected as regulatory assets or liabilities and not as other comprehensive income or current period income. As a result, changes in fair value of these derivatives have no immediate earnings impact.

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

See Note 14 for further information.

Captive Insurance Reserves

Duke Energy has captive insurance subsidiaries that provide coverage, on an indemnity basis, to the Subsidiary Registrants as well as certain third parties, on a limited basis, for financial losses, primarily related to property, workers' compensation and general liability. Liabilities include provisions for estimated losses 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 22 for further information, including significant accounting policies associated with these plans.

Severance and Special Termination Benefits

Duke Energy has severance plans under which in general, the longer a terminated employee worked prior to termination the greater the amount of severance benefits. A liability for involuntary severance is recorded once an involuntary severance plan is committed to by management if involuntary severances are probable and can be reasonably estimated. For involuntary severance benefits incremental to its ongoing severance plan benefits, the fair value of the obligation is expensed at the communication date if there are no future service requirements or over the required future service period. Duke Energy also 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 20 for further information.

Guarantees

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

Stock-Based Compensation

Stock-based compensation represents costs related to stock-based awards granted to employees and 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 21 for further information.

Income Taxes

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

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

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

See Note 23 for further information.

Accounting for Renewable Energy Tax Credits

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

Excise Taxes

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

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Duke Energy	**$ 405**	$ 376	$ 362
Duke Energy Carolinas	**35**	36	31
Progress Energy	**241**	220	213
Duke Energy Progress	**19**	19	18
Duke Energy Florida	**222**	201	195
Duke Energy Ohio	**105**	98	100
Duke Energy Indiana	**22**	20	17
Piedmont[(a)]	**2**	2	

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

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, 2018, and 2017, an insignificant amount of Duke Energy's consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

The new accounting standards adopted for 2018 and 2017 had no material impact on the presentation or results of operations, cash flows or financial position of the Duke Energy Registrants. The following accounting standards were adopted by the Duke Energy Registrants during 2018.

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 expected in exchange for those goods or services. The amendments also required 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. The majority of Duke Energy's revenue is in scope of the new guidance. Other revenue arrangements, such as alternative revenue programs and certain PPAs and lighting agreements accounted for as leases, are excluded from the scope of this guidance and, therefore, are accounted for and evaluated for separate presentation and disclosure under other relevant accounting guidance.

Duke Energy elected the modified retrospective method of adoption effective January 1, 2018. Under the modified retrospective method of adoption, prior year reported results are not restated. Adoption of this standard did not result in a material change in the timing or pattern of revenue recognition and a cumulative-effect adjustment was not recorded at January 1, 2018. Duke Energy utilized certain practical expedients including applying this guidance to open contracts at the date of adoption, expensing costs to obtain a contract where the amortization period of the asset would have been one year or less, ignoring the effects of a significant financing when the period between transfer of the good or service and payment is one year or less and recognizing revenues for certain contracts under the invoice practical expedient, which allows revenue recognition to be consistent with invoiced amounts (including unbilled estimates) provided certain criteria are met, including consideration of whether the invoiced amounts reasonably represent the value provided to customers.

In preparation for adoption, Duke Energy identified material revenue streams and reviewed representative contracts and tariffs, including those associated with certain long-term customer contracts such as wholesale contracts, PPAs and other customer arrangements. Duke Energy also monitored the activities of the power and utilities industry revenue recognition task force and has reviewed published positions on specific industry issues to evaluate the impact, if any, on Duke Energy’s specific contracts and conclusions. Duke Energy applied the available practical expedient to portfolios of tariffs and contracts with similar characteristics. The vast majority of sales, including energy provided to retail customers, are from tariff offerings that provide natural gas or electricity without a defined contractual term ("at-will"). In most circumstances, revenue from contracts with customers is equivalent to the electricity or natural gas supplied and billed in that period (including unbilled estimates). As such, adoption of the new rules did not result in a shift in the timing or pattern of revenue recognition for such sales. While there have been changes to the captions and descriptions of revenues in Duke Energy’s financial statements, the most significant impact as a result of adopting the standard are additional disclosures around the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. See Note 18 for further information.

Financial Instruments Classification and Measurement. On January 1, 2018, Duke Energy adopted FASB guidance, which revised the classification and measurement of certain financial instruments. The adopted guidance changes the presentation of realized and unrealized gains and losses in certain equity securities that were previously recorded in AOCI. These gains and losses are now recorded in net income. 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. This guidance had a 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' equity securities are deferred as regulatory assets or liabilities pursuant to accounting guidance for regulated operations. The resulting adjustment of unrealized gains and losses in AOCI to retained earnings was immaterial. The primary impact to Duke Energy as a result of implementing this guidance is adding disclosure requirements to present separately the financial assets and financial liabilities by measurement category and form of financial asset. See Notes 15 and 16 for further information.

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 Consolidated Statements of Cash Flows. Under the updated guidance, restricted cash and restricted cash equivalents are included within beginning-of-period and end-of-period cash and cash equivalents on the Consolidated Statements of Cash Flows. Duke Energy adopted this guidance on January 1, 2018. The guidance has been applied using a retrospective transition method to each period presented. The adoption by Duke Energy of the revised guidance resulted in a change to the amount of Cash, cash equivalents and restricted cash explained when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statements of Cash Flows. In addition, a reconciliation has been provided of Cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheets that sums to the total of the same such amounts in the Consolidated Statements of Cash Flows. Prior to adoption, the Duke Energy Registrants reflected changes in noncurrent restricted cash within Cash Flows from Investing Activities and changes in current restricted cash within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows.

In August 2016, the FASB issued accounting guidance addressing diversity in practice for eight separate cash flow issues. The guidance requires entities to classify distributions received from equity method investees using either the cumulative earnings approach or the nature of the distribution approach. Duke Energy adopted this guidance on January 1, 2018, and elected the nature of distribution approach. This approach requires all distributions received to be categorized based on legal documentation describing the nature of the activities generating the distribution. Cash inflows resulting in a return on investment (surplus) will be reflected in Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows, whereas cash inflows resulting in a return of investment (capital) will be reflected in Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows. The guidance has been applied using the retrospective transition method to each period presented. There are no changes to the Consolidated Statements of Cash Flows for the periods presented as a result of this accounting change.

Retirement Benefits. In March 2017, the FASB issued revised accounting guidance for the presentation of net periodic costs related to benefit plans. Previous guidance required the aggregation of all the components of net periodic costs on the Consolidated Statements of Operations and did not require the disclosure of the location of net periodic costs on the Consolidated Statements of Operations. Under the amended guidance, the service cost component of net periodic costs is included within Operating Income within the same line as other compensation expenses. All other components of net periodic costs are outside of Operating Income. In addition, the updated guidance permits only the service cost component of net periodic costs to be capitalized to Inventory or Property, Plant and Equipment. This represents a change from previous guidance, which permitted all components of net periodic costs to be eligible for capitalization.

Duke Energy adopted this guidance on January 1, 2018. Under previous guidance, Duke Energy presented the total non-capitalized net periodic costs within Operation, maintenance and other on the Consolidated Statements of Operations. The adoption of this guidance resulted in a retrospective change to reclassify the presentation of the non-service cost (benefit) components of net periodic costs to Other income and expenses. Duke Energy utilized the practical expedient for retrospective presentation. The change in components of net periodic costs eligible for capitalization is applicable prospectively. Since Duke Energy's service cost component is greater than the total net periodic costs, the change results in increased capitalization of net periodic costs, higher Operation, maintenance and other and higher Other income and expenses. The resulting prospective impact to Duke Energy is an immaterial increase in Net Income. See Note 22 for further information.

For Duke Energy, the retrospective change resulted in higher Operation, maintenance and other and higher Other income and expenses, net, of $156 million and $139 million for the years ended December 31, 2017, and 2016, respectively. There was no change to Net Income for these prior periods.

The following new accounting standards have been issued, but have not yet been adopted by the Duke Energy Registrants, as of December 31, 2018.

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

For Duke Energy, this guidance is effective for interim and annual periods beginning January 1, 2019. The guidance will be applied using a modified retrospective approach. Under the modified retrospective approach of adoption, prior year reported results are not restated and a cumulative-effect adjustment, if applicable, is recorded to retained earnings at January 1, 2019. Upon adoption, agreements considered leases for the use of certain aircraft, space on communication towers, industrial equipment, fleet vehicles, fuel transportation (barges and railcars), land and office space will be recognized on the balance sheet. Duke Energy expects to adopt the following practical expedients:

Practical Expedient	Description	Election
Package of transition practical expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to 1) reassess whether any expired or existing contracts are/or contain leases, 2) reassess the lease classification for any expired or existing leases and 3) reassess initial direct costs for any existing leases.	Duke Energy plans to elect this practical expedient.
Short-term lease expedient (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases by asset class.	Duke Energy plans to elect this practical expedient for all asset classes.
Lease and non-lease components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component by asset class.	Duke Energy plans to elect this practical expedient for all asset classes.
Hindsight expedient (when determining lease term)	Elect to use hindsight to determine the lease term.	Duke Energy plans to elect this practical expedient.
Existing and expired land easements not previously accounted for as leases	Elect to not evaluate existing or expired easements under the new guidance and carry forward current accounting treatment.	Duke Energy plans to elect this practical expedient.
Comparative reporting requirements for initial adoption	Elect to apply transition requirements at adoption date, recognize cumulative effect adjustment to retained earnings in period of adoption and not apply ASC 842 to comparative periods, including disclosures.	Duke Energy plans to elect this practical expedient.
Lessor expedient (elect by class of underlying asset)	Elect as an accounting policy to aggregate non-lease components with the related lease component when specified conditions are met by asset class. Account for the combined component based on its predominant characteristic (revenue or operating lease).	Duke Energy plans to elect this practical expedient for all asset classes.

Duke Energy currently expects to record right-of-use assets and operating lease liabilities on its balance sheet as shown in approximate amounts in the table below:

		(in millions)
Duke Energy	$	1,700
Duke Energy Carolinas		150
Progress Energy		850
Duke Energy Progress		400
Duke Energy Florida		450
Duke Energy Ohio		25
Duke Energy Indiana		60
Piedmont		30

In addition to the recognition of operating leases on the balance sheet, Duke Energy expects additional disclosures including both finance and operating lease costs, short-term lease costs, variable lease costs, weighted-average remaining lease term as well as weighted-average discount rates. Duke Energy does not expect a material change to its financial statements from adoption of the new standard for contracts where it is the lessor.

2. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

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

2016 Acquisition of Piedmont Natural Gas

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

Accounting Charges Related to the Acquisition

Duke Energy incurred pretax transaction and integration costs associated with the acquisition of $84 million, $103 million and $439 million for the years ended December 31, 2018, 2017 and 2016, respectively. Amounts recorded on the Consolidated Statements of Operations in 2018 and 2017 were primarily system integration costs of $78 million and $71 million, respectively, related to combining the various operational and financial systems of Duke Energy and Piedmont, including a one-time software impairment resulting from planned accounting system and process integration in 2017. A $7 million charge was recorded within Impairment Charges, with the remaining $64 million recorded within Operation, maintenance and other in 2017.

Amounts recorded in 2016 include:

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

The majority of transition and integration activities were completed by the end of 2018.

Pro Forma Financial Information

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

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.

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

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.

DISPOSITIONS

For the years ended December 31, 2018, and 2017, the Income (Loss) from Discontinued Operations, net of tax, was immaterial. The following table summarizes the Loss from Discontinued Operations, net of tax recorded on Duke Energy's Consolidated Statements of Operations for the year ended December 31, 2016:

		Year Ended December 31,
(in millions)		**2016**
International Disposal Group	$	(534)
Other[(a)]		126
Loss from Discontinued Operations, net of tax	$	(408)

(a) Amount represents an income tax benefit resulting from immaterial out of period deferred tax liability adjustments for previously sold businesses not related to the International Disposal Group.

2016 Sale of International Energy

In February 2016, Duke Energy announced it had initiated a process to divest 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 the Parent debt. Existing favorable tax attributes result in no immediate U.S. federal-level cash tax impacts. Details of each transaction are as follows:

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

Assets Held For Sale and Discontinued Operations

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

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

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

(a) Upon meeting the criteria for assets held for sale, beginning in the fourth quarter of 2016 depreciation expense 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 attributable to Duke Energy Corporation was $(445) million for the year ended December 31, 2016.

(e) 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) Amount includes an income tax benefit of $95 million. See Note 23, "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.

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

Other Sale Related Matters

During 2017, Duke Energy provided certain transition services to CTG and I Squared Capital. Cash flows related to providing the transition services were not material as of December 31, 2017. All transition services related to the International Disposal Group ended in 2017. Additionally, Duke Energy will reimburse CTG and I Squared Capital for all tax obligations arising from the period preceding consummation on the transactions, and recorded a liability of $54 million and $78 million as of December 31, 2018, and 2017, respectively. Duke Energy has not recorded any other liabilities, contingent liabilities or indemnifications related to the International Disposal Group.

3. BUSINESS SEGMENTS

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

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

Duke Energy

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

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

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

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

The remainder of Duke Energy's operations is presented as Other, which is primarily comprised of interest expense on holding company debt, unallocated corporate costs and Duke Energy's wholly owned captive insurance company, Bison. Other also includes Duke Energy's interest in NMC. See Note 12 for additional information on the investment in NMC.

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

	Year Ended December 31, 2018						
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Commercial Renewables**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Unaffiliated Revenues	$ 22,242	$ 1,783	$ 477	$ 24,502	$ 19	$ —	$ 24,521
Intersegment Revenues	31	98	—	129	70	(199)	—
Total Revenues	$ 22,273	$ 1,881	$ 477	$ 24,631	$ 89	$ (199)	$ 24,521
Interest Expense	$ 1,288	$ 106	$ 88	$ 1,482	$ 657	$ (45)	$ 2,094
Depreciation and amortization	3,523	245	155	3,923	152	(1)	4,074
Equity in earnings (losses) of unconsolidated affiliates	5	27	(1)	31	52	—	83
Income tax expense (benefit)(a)	799	78	(147)	730	(282)	—	448
Segment income (loss)(b)(c)(d)(e)	3,058	274	9	3,341	(694)	—	2,647
Add back noncontrolling interest component							(22)
Income from discontinued operations, net of tax							19
Net income							$ 2,644
Capital investments expenditures and acquisitions	$ 8,086	$ 1,133	$ 193	$ 9,412	$ 256	$ —	$ 9,668
Segment assets	125,364	12,361	4,204	141,929	3,275	188	145,392

(a) All segments include adjustments to the December 31, 2017 estimate of the income tax effects of the Tax Act. Electric Utilities and Infrastructure includes a $24 million expense, Gas Utilities and Infrastructure includes a $1 million expense, Commercial Renewables includes a $3 million benefit and Other includes a $2 million benefit. See Note 23 for additional information.

(b) Electric Utilities and Infrastructure includes after-tax regulatory and legislative impairment charges of $202 million related to rate case orders, settlements or other actions of regulators or legislative bodies and an after-tax impairment charge of $46 million related to the Citrus County CC at Duke Energy Florida. See Note 4 for additional information.

(c) Gas Utilities and Infrastructure includes an after-tax impairment charge of $42 million for the investment in Constitution. See Note 12 for additional information.

(d) Commercial Renewables includes an impairment charge of $91 million, net of $2 million Noncontrolling interests, related to goodwill. See Note 11 for additional information.

(e) Other includes $65 million of after-tax costs to achieve the Piedmont merger, $144 million of after-tax severance charges related to a companywide initiative and an $82 million after-tax loss on the sale of the retired Beckjord Generating Station described below. For additional information, see Note 2 for the Piedmont Merger and Note 20 for severance charges.

In February 2018, Duke Energy sold Beckjord, a nonregulated facility retired during 2014, and recorded a pretax loss of $106 million within (Losses) Gains on Sales of Other Assets and Other, net and $1 million within Operation, maintenance and other on Duke Energy's Consolidated Statements of Operations for the year ended December 31, 2018. The sale included the transfer of coal ash basins and other real property and indemnification from any and all potential future claims related to the property, whether arising under environmental laws or otherwise.

	Year Ended December 31, 2017						
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Commercial Renewables**	**Total Reportable Segments**	**Other**	**Eliminations**	**Total**
Unaffiliated Revenues	$ 21,300	$ 1,743	$ 460	$ 23,503	$ 62	$ —	$ 23,565
Intersegment Revenues	31	93	—	124	76	(200)	—
Total Revenues	$ 21,331	$ 1,836	$ 460	$ 23,627	$ 138	$ (200)	$ 23,565
Interest Expense	$ 1,240	$ 105	$ 87	$ 1,432	$ 574	$ (20)	$ 1,986
Depreciation and amortization	3,010	231	155	3,396	131	—	3,527
Equity in earnings (losses) of unconsolidated affiliates	5	62	(5)	62	57	—	119
Income tax expense (benefit)(a)	1,355	116	(628)	843	353	—	1,196
Segment income (loss)(b)(c)(d)	3,210	319	441	3,970	(905)	—	3,065
Add back noncontrolling interest component							5
Loss from discontinued operations, net of tax							(6)
Net income							$ 3,064
Capital investments expenditures and acquisitions	$ 7,024	$ 907	$ 92	$ 8,023	$ 175	$ —	$ 8,198
Segment assets	119,423	11,462	4,156	135,041	2,685	188	137,914

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

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

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

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

	Year Ended December 31, 2016						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 21,336	$ 875	$ 484	$ 22,695	$ 48	$ —	$ 22,743
Intersegment Revenues	30	26	—	56	69	(125)	—
Total Revenues	$ 21,366	$ 901	$ 484	$ 22,751	$ 117	$ (125)	$ 22,743
Interest Expense	$ 1,136	$ 46	$ 53	$ 1,235	$ 693	$ (12)	$ 1,916
Depreciation and amortization	2,897	115	130	3,142	152	—	3,294
Equity in earnings (losses) of unconsolidated affiliates(a)	5	19	(82)	(58)	43	—	(15)
Income tax expense (benefit)	1,672	90	(160)	1,602	(446)	—	1,156
Segment income (loss)(b)(c)	3,040	152	23	3,215	(645)	1	2,571
Add back noncontrolling interest component							7
Loss from discontinued operations, net of tax(d)							(408)
Net income							$ 2,170
Capital investments expenditures and acquisitions(e)	$ 6,649	$ 5,519	$ 857	$ 13,025	$ 190	$ —	$ 13,215
Segment assets	114,993	10,760	4,377	130,130	2,443	188	132,761

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

(b) Other includes $329 million of after-tax costs to achieve mergers. See 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. See Note 20 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 investment expenditures related to the International Disposal Group. Gas Utilities and Infrastructure includes the Piedmont acquisition of $5 billion. See Note 2 for more information on the Piedmont acquisition.

Geographical Information

All assets and revenues from continuing operations are within the U.S.

Major Customers

For the year ended December 31, 2018, revenues from one customer of Duke Energy Progress are $633 million. Duke Energy Progress has one reportable segment, Electric Utilities and Infrastructure. No other Subsidiary Registrant has an individual customer representing more than 10 percent of its revenues.

Products and Services

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

(in millions)	Retail Electric	Wholesale Electric	Retail Natural Gas	Other	Total Revenues
2018					
Electric Utilities and Infrastructure	**$ 19,013**	**$ 2,345**	**$ —**	**$ 915**	**$ 22,273**
Gas Utilities and Infrastructure	**—**	**—**	**1,817**	**64**	**1,881**
Commercial Renewables	**—**	**375**	**—**	**102**	**477**
Total Reportable Segments	**$ 19,013**	**$ 2,720**	**$ 1,817**	**$ 1,081**	**$ 24,631**
2017					
Electric Utilities and Infrastructure	$ 18,177	$ 2,104	$ —	$ 1,050	$ 21,331
Gas Utilities and Infrastructure	—	—	1,732	104	1,836
Commercial Renewables	—	375	—	85	460
Total Reportable Segments	$ 18,177	$ 2,479	$ 1,732	$ 1,239	$ 23,627
2016					
Electric Utilities and Infrastructure	$ 18,338	$ 2,095	$ —	$ 933	$ 21,366
Gas Utilities and Infrastructure	—	—	871	30	901
Commercial Renewables	—	303	—	181	484
Total Reportable Segments	$ 18,338	$ 2,398	$ 871	$ 1,144	$ 22,751

Duke Energy Ohio

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

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

The remainder of Duke Energy Ohio's operations is presented as Other. In December 2018, the PUCO approved an order which allows the recovery or credit of revenues and expenses related to Duke Energy Ohio's contractual arrangement to buy power from OVEC power plants. Due to the change in regulatory treatment of these amounts, OVEC revenues and expenses are now reflected in the Electric Utilities and Infrastructure segment. Previously, OVEC revenues and expense were included in Other. These amounts are deemed immaterial for Duke Energy Ohio. Therefore, no prior period amounts were restated. See Note 4 for additional information on the PUCO order.

All Duke Energy Ohio assets and revenues from continuing operations are within the U.S.

	Year Ended December 31, 2018				
(in millions)	**Electric Utilities and Infrastructure**	**Gas Utilities and Infrastructure**	**Total Reportable Segments**	**Other**	**Total**
Total revenues	**$ 1,450**	**$ 506**	**$ 1,956**	**$ 1**	**$ 1,957**
Interest expense	**$ 67**	**$ 24**	**$ 91**	**$ 1**	**$ 92**
Depreciation and amortization	**183**	**85**	**268**	**—**	**268**
Income tax expense (benefit)	**47**	**24**	**71**	**(28)**	**43**
Segment income (loss)/Net income[(a)]	**186**	**93**	**279**	**(103)**	**176**
Capital expenditures	**$ 655**	**$ 172**	**$ 827**	**$ —**	**$ 827**
Segment assets	**5,643**	**2,874**	**8,517**	**38**	**8,555**

(a) Other includes the loss on the sale of Beckjord, see discussion above.

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

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

4. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

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

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

	Duke Energy		Progress Energy	
	December 31,		December 31,	
(in millions)	2018	2017	2018	2017
Regulatory Assets				
AROs – coal ash	$ **4,255**	$ 4,025	$ **2,061**	$ 1,984
AROs – nuclear and other	**772**	852	**601**	655
Accrued pension and OPEB	**2,654**	2,249	**1,074**	906
Retired generation facilities	**445**	480	**367**	386
Debt fair value adjustment	**1,099**	1,197	**—**	—
Deferred asset – Lee COLA	**383**	—	**—**	—
Storm cost deferrals	**1,117**	531	**953**	526
Nuclear asset securitized balance, net	**1,093**	1,142	**1,093**	1,142
Hedge costs deferrals	**204**	234	**74**	94
Derivatives – natural gas supply contracts	**141**	142	**—**	—
Demand side management (DSM)/Energy efficiency (EE)	**449**	530	**256**	281
Grid modernization	**31**	39	**—**	—
Vacation accrual	**213**	213	**41**	42
Deferred fuel and purchased power	**838**	507	**600**	349
Nuclear deferral	**133**	119	**46**	35
Post-in-service carrying costs (PISCC) and deferred operating expenses	**320**	366	**36**	38
Transmission expansion obligation	**39**	46	**—**	—
Manufactured gas plant (MGP)	**99**	91	**—**	—
Advanced metering infrastructure (AMI)	**367**	362	**127**	150
NCEMPA deferrals	**50**	53	**50**	53
East Bend deferrals	**47**	45	**—**	—
Deferred pipeline integrity costs	**65**	54	**—**	—
Amounts due from customers	**24**	64	**—**	—
Other	**784**	538	**322**	110
Total regulatory assets	**15,622**	13,879	**7,701**	6,751
Less: current portion	**2,005**	1,437	**1,137**	741

Total noncurrent regulatory assets	**$**	**13,617**	$	12,442	**$**	**6,564**	$	6,010
Regulatory Liabilities								
Costs of removal	**$**	**5,421**	$	5,968	**$**	**2,135**	$	2,537
AROs – nuclear and other		**538**		806		**—**		—
Net regulatory liability related to income taxes		**8,058**		8,113		**2,710**		2,802
Amounts to be refunded to customers		**34**		10		**—**		—
Storm reserve		**—**		20		**—**		—
Accrued pension and OPEB		**301**		146		**149**		—
Deferred fuel and purchased power		**16**		47		**16**		1
Other		**1,064**		622		**319**		179
Total regulatory liabilities		**15,432**		15,732		**5,329**		5,519
Less: current portion		**598**		402		**280**		213
Total noncurrent regulatory liabilities	**$**	**14,834**	$	15,330	**$**	**5,049**	$	5,306

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

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

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

Accrued pension and OPEB. Accrued pension and OPEB represent regulatory assets and liabilities related to each of the Duke Energy Registrants' respective shares of unrecognized actuarial gains and losses and unrecognized prior service cost and credit attributable to Duke Energy's pension plans and OPEB plans. The regulatory asset or liability is amortized with the recognition of actuarial gains and losses and prior service cost and credit to net periodic benefit costs for pension and OPEB plans. The accrued pension and OPEB regulatory asset is expected to be recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.

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

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

Net regulatory asset or liability related to income taxes. Amounts for all registrants include regulatory liabilities related primarily to impacts from the Tax Act. See Note 23 for additional information. Amounts have no immediate impact on rate base as regulatory assets are offset by deferred tax liabilities.

Deferred asset – Lee COLA. Represents deferred costs incurred for the canceled Lee nuclear project.

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

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

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

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

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

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

Vacation accrual. Represents.vacation entitlement, which is generally recovered in the following year.

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

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

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

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 Duke Energy Ohio's East End and West End sites.

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

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

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

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

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

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

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

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

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

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

Duke Energy Progress and Duke Energy Florida also have restrictions imposed by their first mortgage bond indentures, which in certain circumstances, limit their ability to make cash dividends or distributions on common stock. Amounts restricted as a result of these provisions were not material at December 31, 2018.

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 not a material amount of Duke Energy's and Progress Energy's net assets at December 31, 2018.

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 merger not been applied to Duke Energy Ohio’s balance sheet. The conditions include a commitment from Duke Energy Ohio that equity, adjusted to remove the impacts of push-down accounting, will not fall below 30 percent of total capital.

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

Duke Energy Indiana

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

Piedmont

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

RATE-RELATED INFORMATION

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

Duke Energy Carolinas and Duke Energy Progress

Grid Improvement – South Carolina

On June 22, 2018, Duke Energy Carolinas and Duke Energy Progress filed a joint petition with the PSCSC seeking an accounting order authorizing deferral of certain costs incurred in connection with grid reliability, resiliency and modernization work that is being performed under the companies’ grid improvement initiative. On October 3, 2018, the PSCSC granted Duke Energy Carolinas' and Duke Energy Progress' joint petition, which authorizes the deferral of these costs until the rate effective dates of each Company’s next general rate case.

Hurricane Florence, Hurricane Michael and Winter Storm Diego

In September 2018, Hurricane Florence made landfall and inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 2 million customers were impacted. The companies incurred approximately $500 million in incremental operation and maintenance expenses ($70 million and $430 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) and approximately $90 million in capital costs ($5 million and $85 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) which are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, resulting from the hurricane restoration efforts. Most of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. The balance of operation and maintenance expenses are included in Operation, maintenance and other on the Consolidated Statements of Operations for the year ended December 31, 2018.

In October 2018, the remnants of Hurricane Michael inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 1 million customers were impacted. The companies incurred approximately $100 million in incremental operation and maintenance expenses ($75 million and $25 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) and approximately $21 million in capital costs ($12 million and $9 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) which are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, resulting from the hurricane restoration efforts. Most of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. The balance of operation and maintenance expenses are included in Operation, maintenance and other on the Consolidated Statements of Operations for the year ended December 31, 2018.

In December 2018, Winter Storm Diego inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 800,000 customers were impacted. The companies incurred approximately $85 million in incremental operation and maintenance expenses ($60 million and $25 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) and approximately $9 million in capital costs ($7 million and $2 million for Duke Energy Carolinas and Duke Energy Progress, respectively,) which are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018, resulting from the winter storm restoration efforts. Most of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. The balance of operation and maintenance expenses are included in Operation, maintenance and other on the Consolidated Statements of Operations for the year ended December 31, 2018.

On December 21, 2018, Duke Energy Carolinas and Duke Energy Progress filed with the NCUC petitions for approval to defer the incremental costs incurred to a regulatory asset for recovery in the next base rate case. The NCUC issued an order requesting comments on the deferral positions. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter. Duke Energy Progress filed a similar request with the PSCSC on January 11, 2019, which also included a request for the continuation of prior deferrals requested for ice storms and Hurricane Matthew, and on January 30, 2019, the PSCSC issued a directive approving the deferral request.

North Carolina State Corporate Income Tax

On December 12, 2018, Duke Energy Carolinas and Duke Energy Progress filed requests to reduce their rates effective January 1, 2019, based on a reduction in North Carolina's corporate income tax rate from 3 to 2.5 percent, as enacted by the General Assembly in Session Law 2017-57, which became law on June 28, 2017, with an effective date of January 1, 2019. On December 17, 2018, the NCUC issued orders approving the Duke Energy Carolinas and Duke Energy Progress rate decrements.

Duke Energy Carolinas

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash	**$ 1,725**	$ 1,645	(i)	(b)
Accrued pension and OPEB	**581**	410		(j)
Retired generation facilities[c]	**21**	29	X	2023
Deferred Asset – Lee COLA	**383**	—		(b)
Storm cost deferrals	**160**	—	X	(b)
Hedge costs deferrals[c]	**101**	109	X	2041
DSM/EE	**169**	210	(h)	(h)
Vacation accrual	**78**	83	(e)	2019
Deferred fuel and purchased power	**196**	140	(f)	2020
Nuclear deferral	**87**	84		2020
PISCC[c]	**34**	35	X	(b)
AMI	**176**	185	X	(b)
Other	**266**	222		(b)
Total regulatory assets	**3,977**	3,152		
Less: current portion	**520**	299		
Total noncurrent regulatory assets	**$ 3,457**	$ 2,853		
Regulatory Liabilities[a]				
Costs of removal[c]	**$ 1,968**	$ 2,054	X	(g)
ARO – nuclear and other	**538**	806		(b)
Net regulatory liability related to income taxes[d]	**3,082**	3,028		(b)

Storm reserve(c)		**—**	20		(b)
Accrued pension and OPEB		**38**	44		(j)
Deferred fuel and purchased power		**—**	46	(f)	2020
Other		**572**	359		(b)
Total regulatory liabilities		**6,198**	6,357		
Less: current portion		**199**	126		
Total noncurrent regulatory liabilities	**$**	**5,999** $	6,231		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Includes regulatory liabilities related to the change in the federal tax rate as a result of the Tax Act and the change in the North Carolina tax rate, both discussed in Note 23.
(e) Earns a return on outstanding balance in North Carolina.
(f) Pays interest on over-recovered costs in North Carolina. Includes certain purchased power costs in North Carolina and South Carolina and costs of distributed energy in South Carolina.
(g) Recovered over the life of the associated assets.
(h) Includes incentives on DSM/EE investments and is recovered through an annual rider mechanism.
(i) Earns a debt and equity return on coal ash expenditures for North Carolina and South Carolina retail customers as permitted by various regulatory orders.
(j) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.

2017 North Carolina Rate Case

On August 25, 2017, Duke Energy Carolinas filed an application with the NCUC for a rate increase for retail customers of approximately $647 million, which represented an approximate 13.6 percent increase in annual base revenues. The rate increase was driven by capital investments subsequent to the previous base rate case, including the W.S. Lee CC discussed below, grid improvement projects, AMI, investments in customer service technologies, costs of complying with CCR regulations and the Coal Ash Act and recovery of costs related to licensing and development of the Lee Nuclear Station discussed below.

On February 28, 2018, Duke Energy Carolinas and the North Carolina Public Staff (Public Staff) filed an Agreement and Stipulation of Partial Settlement resolving certain portions of the proceeding. Terms of the settlement included a return on equity of 9.9 percent and a capital structure of 52 percent equity and 48 percent debt. As a result of the settlement, Duke Energy Carolinas recorded a pretax charge of approximately $4 million to Operation, maintenance and other on the Consolidated Statements of Operations.

On June 1, 2018, Duke Energy Carolinas and certain intervenors filed a Pilot Grid Rider Agreement and Stipulation (Grid Rider Stipulation) in which the parties agreed to the proposal Duke Energy Carolinas introduced in a post-hearing brief on April 27, 2018, along with additional commitments by Duke Energy Carolinas. Also on June 1, 2018, Duke Energy Carolinas and the Commercial Group filed a Partial Stipulation and Settlement Agreement to be considered in conjunction with the Stipulation.

Components of the Grid Rider Stipulation included:

- Duke Energy Carolinas would recover grid improvement costs through a pilot, three-year Grid Rider except for costs related to targeted undergrounding of power lines, cable and conduit replacement, and power pole replacement;
- Excluded costs were to be deferred with a return until Duke Energy Carolinas' next base rate case proceeding; and
- Costs incurred during the three-year pilot, both rider recoverable and deferred, were subject to a 4.5 percent cumulative cap of total annual electric service revenue.

On June 22, 2018, the NCUC issued an order approving the Stipulation of Partial Settlement and requiring a revenue reduction. The order also included the following material components not covered in the Stipulation:

- Recovery of $554 million of deferred coal ash basin closure costs over a five-year period with a return at Duke Energy Carolinas' WACC;

- Assessment of a $70 million management penalty ratably over a five-year period by reducing the annual recovery of the deferred coal ash costs;
- Denial of Duke Energy Carolinas' request for recovery of future estimated ongoing annual coal ash costs of $201 million with approval to defer such costs with a return at Duke Energy Carolinas' WACC, to be considered for recovery in the next rate case;
- Inclusion in rates of costs related to the W.S. Lee CC, two new solar facilities, and AMI deployment as requested;
- Recovery of Lee Nuclear Station licensing and development cost of $347 million over a 12-year period, but denial of a return on the deferred balance of costs;
- Reduction in revenue related to lower income tax expense resulting from the Tax Act, and a requirement to maintain all excess deferred income tax (EDIT) resulting from the Tax Act in a regulatory liability account pending flow back to customers as approved by the commission at the earlier of three years or Duke Energy Carolinas' next general rate case proceeding; and
- Denial of the proposed Grid Rider Stipulation related to grid improvement costs and denial of deferral accounting treatment of the costs at this time. Duke Energy Carolinas may petition for deferral of grid modernization costs outside of a general rate case proceeding if it can show financial hardship or a stipulation that includes greater consensus among intervening parties on costs being classified as grid modernization.

As a result of the Order, Duke Energy Carolinas recorded a pretax charge of approximately $150 million to Impairment charges and Operation, maintenance and other on the Consolidated Statements of Operations. The charge is primarily related to the denial of a return on the Lee Nuclear Project and for previously recognized return impacted by the coal ash management penalty described above. On July 27, 2018, NCUC approved Duke Energy Carolinas' compliance filing. As a result, revised customer rates were effective on August 1, 2018.

On July 20, 2018, the North Carolina Attorney General filed a Notice of Appeal to the North Carolina Supreme Court from the June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction issued by the NCUC. The Attorney General contends the commission's order should be reversed and remanded, as it is in excess of the commission's statutory authority; affected by errors of law; unsupported by competent, material and substantial evidence in view of the entire record as submitted; and arbitrary or capricious. The Sierra Club, North Carolina Sustainable Energy Association, North Carolina Justice Center, North Carolina Housing Coalition, Natural Resource Defense Council and Southern Alliance for Clean Energy have also filed Notices of Appeal to the North Carolina Supreme Court from the June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction. On August 8, 2018, the Public Staff filed a Notice of Cross Appeal to the North Carolina Supreme Court from the June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction issued by the NCUC. The Public Staff contends the commission's order should be reversed and remanded, as it is affected by errors of law, and is unsupported by substantial evidence with regard to the commission's failure to consider substantial evidence of coal ash related environmental violations. On November 29, 2018, the North Carolina Attorney General's Office filed a motion with the North Carolina Supreme Court requesting the court consolidate the Duke Energy Carolinas and Duke Energy Progress appeals and enter an order adopting the parties' proposed briefing schedule as set out in the filing. On November 29, 2018, the North Carolina Supreme Court adopted a schedule for briefing set forth in the motion to consolidate the Duke Energy Carolinas and Duke Energy Progress appeals. The Appellee response briefs are due July 29, 2019. Duke Energy Carolinas cannot predict the outcome of this matter.

2018 South Carolina Rate Case

On November 8, 2018, Duke Energy Carolinas filed an application with the PSCSC for a rate increase for retail customers of approximately $168 million, which represents an approximate 10.0 percent increase in retail revenues. The rate increase is driven by capital investments and environmental compliance progress made by Duke Energy Carolinas since its previous rate case, including the further implementation of Duke Energy Carolinas' generation modernization program, which consists of retiring, replacing and upgrading generation plants, investments in customer service technologies and continued investments in base work to maintain its transmission and distribution systems. The request includes net tax benefits resulting from the Tax Act of $66 million to reflect the change in ongoing tax expense, primarily from the reduction in the federal income tax rate from 35 to 21 percent, and $46 million to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change and benefits of $17 million from a reduction in North Carolina state income taxes allocable to South Carolina.

Duke Energy Carolinas also requested approval of its proposed Grid Improvement Plan, adjustments to its Prepaid Advantage Program and a variety of accounting orders related to ongoing costs for environmental compliance, including recovery over a five-year period of $242 million of deferred coal ash related compliance costs, grid investments between rate changes, incremental depreciation expense, a result of new depreciation rates from the depreciation study approved in the 2017 North Carolina Rate Case above, and the balance of development costs associated with the cancellation of the Lee Nuclear Project. Finally, Duke Energy Carolinas sought approval to establish a reserve and accrual for end of life nuclear costs for nuclear fuel and materials and supplies. An evidentiary hearing is scheduled to begin on March 21, 2019, and a decision and revised customer rates are expected by mid-2019. Duke Energy Carolinas cannot predict the outcome of this matter.

FERC Formula Rate Matter

On July 31, 2017, PMPA filed a complaint with FERC alleging that Duke Energy Carolinas misapplied the formula rate under the PPA between the parties by including in its rates amortization expense associated with regulatory assets and recorded in a certain account without FERC approval. On February 15, 2018, FERC issued an order ruling in favor of PMPA and ordered Duke Energy Carolinas to refund to PMPA all amounts improperly collected under the PPA. Duke Energy Carolinas has issued to PMPA and similarly situated wholesale customers refunds of approximately $25 million. FERC also set the matter for settlement and hearing. PMPA and other customers filed a protest to Duke Energy Carolinas' refund report claiming that the refunds are inadequate in that (1) Duke Energy Carolinas invoked the limitations periods in the contracts to limit the time period for which the refunds were paid and the customers disagree that this limitation applies, and (2) Duke Energy Carolinas refunded only amounts recovered through a certain account and the customers have asserted that the order applies to all regulatory assets. On July 3, 2018, FERC issued an order accepting Duke Energy Carolinas' refund report and ruling that these two claims are outside the scope of FERC's February order. The settlement agreements and revised formula rates for all parties to the proceeding were filed on December 28, 2018. Duke Energy Carolinas cannot predict the outcome of this matter.

W.S. Lee CC

On April 9, 2014, the PSCSC granted Duke Energy Carolinas and NCEMC a CECPCN for the construction and operation of a 750-megawatt (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 its share of the cost to build the facility was approximately $650 million, including AFUDC. Approximately $600 million is being recovered through base rate or deferral filings in North Carolina and South Carolina. The remaining amount will be included in future rate filings. The project commenced commercial operation on April 5, 2018. NCEMC owns approximately 13 percent of the project.

Lee Nuclear Station

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

The Duke Energy Carolinas 2017 North Carolina Rate Case filing discussed above included a request to cancel the development of the Lee Nuclear project, recover incurred licensing and development costs and maintain the license issued by the NRC as an option for potential future development. The cancellation request was due to the Westinghouse bankruptcy filing and other market activity. The NCUC Order issued on June 22, 2018, approved the cancellation of the Lee Nuclear Project, allowed Duke Energy Carolinas to continue to maintain the COLs, provided for recovery of the North Carolina retail allocation of project development costs, including AFUDC accrued through December 31, 2017, over 12 years and disallowed any return on the unamortized balance during the 12-year recovery period.

Given the repeal of certain sections of the Base Load Review Act in South Carolina combined with the cancellation of the project, Duke Energy Carolinas determined that it was no longer probable it would be allowed a return on its share of project development costs attributable to South Carolina. As a result, Duke Energy Carolinas recorded a pretax impairment in the second quarter of 2018 of $29 million within Impairment charges on the Consolidated Statements of Operations and Comprehensive Income.

South Carolina Petition

On June 22, 2018, Duke Energy Carolinas filed a petition with the PSCSC requesting an accounting order to defer certain costs incurred in connection with the addition of the W.S. Lee CC, the ongoing deployment of Duke Energy Carolinas new billing and Customer Information System and the addition of the Carolinas West Primary Distribution Control Center. This request totaling approximately $33 million was approved on July 25, 2018.

Sale of Hydroelectric (Hydro) Plants

In May 2018, Duke Energy Carolinas entered an agreement for the sale of five hydro plants with a combined 18.7-MW generation capacity in the Western Carolinas region to Northbrook Energy. The completion of the transaction is subject to approval from FERC for the four FERC-licensed plants, as well as other state regulatory agencies and is contingent upon regulatory approval from the NCUC and PSCSC to defer the total estimated loss on the sale of approximately $40 million. On July 5, 2018, Duke Energy Carolinas filed with NCUC for approval of the sale of the five hydro plants to Northbrook, to transfer the CPCNs for the four North Carolina hydro plants and to establish a regulatory asset for the North Carolina retail portion of the difference between sales proceeds and net book value. On September 4, 2018, the Public Staff filed comments supporting the CPCN transfer with conditions. On September 18, 2018, Duke Energy Carolinas filed reply comments opposing the Public Staff's proposed conditions. On November 29, 2018, the NCUC issued a procedural order and held an evidentiary hearing on this matter on February 5, 2019. On August 28, 2018, Duke Energy Carolinas filed with PSCSC its Application for Approval of Transfer and Sale of Hydroelectric Generation Facilities, Acceptance for Filing of a Power Purchase Agreement and an Accounting Order to Establish a Regulatory Asset. On September 10, 2018, the ORS provided a letter to the commission stating its position on the application and on September 18, 2018, Duke Energy Carolinas requested this matter be carried over to allow Duke Energy Carolinas time to discuss certain accounting issues with the ORS. On August 9, 2018, Duke Energy Carolinas and Northbrook filed a joint Application for Transfer of Licenses with the FERC. On December 27, 2018, the FERC issued its Order Approving Transfer of Licenses ("Order") for the four FERC-licensed hydro plants. On January 18, 2019, Duke Energy Carolinas and Northbrook Carolina Hydro II, LLC requested a six-month extension of time to comply with the requirement of the Order that Northbrook submit to FERC certified copies of all instruments of conveyance and signed acceptance sheets within 60 days of the date of the Order, given that compliance by the deadline set in the Order is not possible because the conveyance of the projects is contingent on the receipt of state regulatory approvals, which are not anticipated to be issued by February 25, 2019.

If commission approvals are not received, Duke Energy Carolinas can cancel the sales agreement and retain the hydro facilities. If commission approvals are received, the closing is expected to occur during the second quarter of 2019. After closing, Duke Energy Carolinas will purchase all the capacity and energy generated by these facilities at the avoided cost for five years through power purchase agreements. Duke Energy Carolinas cannot predict the outcome of this matter.

Duke Energy Progress

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash	**$ 2,051**	$ 1,975	(h)	(b)
AROs – nuclear and other	**429**	359		(c)
Accrued pension and OPEB	**542**	430		(k)
Retired generation facilities	**148**	170	X	(b)
Storm cost deferrals[d]	**571**	150	X	(b)
Hedge costs deferrals	**54**	64		(b)
DSM/EE[e]	**235**	264	(i)	(i)
Vacation accrual	**41**	42		2019
Deferred fuel and purchased power	**397**	130	(f)	2020
Nuclear deferral	**46**	35		2020
PISCC and deferred operating expenses	**36**	38	X	2054
AMI	**67**	75		(b)
NCEMPA deferrals	**50**	53	(g)	2042
Other	**147**	74		(b)
Total regulatory assets	**4,814**	3,859		
Less: current portion	**703**	352		
Total noncurrent regulatory assets	**$ 4,111**	$ 3,507		

Regulatory Liabilities[a]

Costs of removal	**$ 1,878**	$ 2,122	X	(j)
Accrued pension and OPEB	**93**	—		(k)
Net regulatory liability related to income taxes[l]	**1,863**	1,854		(b)
Deferred fuel and purchased power	**—**	1	(f)	2020
Other	**299**	161		(b)
Total regulatory liabilities	**4,133**	4,138		
Less: current portion	**178**	139		
Total noncurrent regulatory liabilities	**$ 3,955**	$ 3,999		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Recovery period for costs related to nuclear facilities runs through the decommissioning period of each unit.
(d) South Carolina storm costs are included in rate base.
(e) Included in rate base.
(f) Pays interest on over-recovered costs in North Carolina. Includes certain purchased power costs in North Carolina and South Carolina and costs of distributed energy in South Carolina.
(g) South Carolina retail allocated costs are earning a return.
(h) Earns a debt and equity return on coal ash expenditures for North Carolina and South Carolina retail customers as permitted by various regulatory orders.
(i) Includes incentives on DSM/EE investments and is recovered through an annual rider mechanism.
(j) Recovered over the life of the associated assets.
(k) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.
(l) Includes regulatory liabilities related to the change in the federal tax rate as a result of the Tax Act and the change in the North Carolina tax rate, both discussed in Note 23.

2017 North Carolina Rate Case

On June 1, 2017, Duke Energy Progress filed an application with the NCUC for a rate increase for retail customers of approximately $477 million, which represented an approximate 14.9 percent increase in annual base revenues. Subsequent to the filing, Duke Energy Progress adjusted the requested amount to $420 million, representing an approximate 13 percent increase. The rate increase is driven by capital investments subsequent to the previous base rate case, costs of complying with CCR regulations and the Coal Ash Act, costs relating to storm recovery, investments in customer service technologies and recovery of costs associated with renewable purchased power.

On December 16, 2016, Duke Energy Progress filed a petition with the NCUC requesting an accounting order to defer certain costs incurred in connection with response to Hurricane Matthew and other significant storms in 2016. The final estimate of incremental operation and maintenance and capital costs of $116 million was filed with the NCUC in September 2017. On July 10, 2017, the NCUC consolidated Duke Energy Progress' storm deferral request into the Duke Energy Progress rate case docket for decision.

On November 22, 2017, Duke Energy Progress and the Public Staff filed an Agreement and Stipulation of Partial Settlement resolving certain portions of the proceeding. Terms of the settlement included a return on equity of 9.9 percent and a capital structure of 52 percent equity and 48 percent debt. As a result of the settlement, in 2017 Duke Energy Progress recorded pretax charges totaling approximately $25 million to Impairment charges and Operation, maintenance and other on the Consolidated Statements of Operations, principally related to disallowances from rate base of certain projects at the Mayo and Sutton plants. On February 23, 2018, the NCUC issued an order approving the stipulation. The order also included the following material components not covered in the stipulation:

- Recovery of the remaining $234 million of deferred coal ash basin closure costs over a five-year period with a return at Duke Energy Progress' WACC, excluding $10 million of retail deferred coal ash basin costs related to ash hauling at Duke Energy Progress' Asheville Plant;
- Assessment of a $30 million management penalty ratably over a five-year period by reducing the annual recovery of the deferred coal ash costs;

- Denial of Duke Energy Progress' request for recovery of future estimated ongoing annual coal ash costs of $129 million with approval to defer such costs with a return at Duke Energy Progress' WACC, to be considered for recovery in the next rate case; and
- Approval to recover $51 million of the approximately $80 million deferred storm costs over a five-year period with amortization beginning in October 2016. The order did not allow the deferral of the associated capital costs or a return on the deferred balance during the deferral period.

The order also impacted certain amounts that were similarly recorded on Duke Energy Carolinas' Consolidated Balance Sheets. As a result of the order, Duke Energy Progress and Duke Energy Carolinas recorded pretax charges of $68 million and $14 million, respectively, in the first quarter of 2018 to Impairment charges, Operation, maintenance and other and Interest Expense on the Consolidated Statements of Operations. These charges primarily related to the coal ash basin disallowance and previously recognized return impacted by the coal ash management penalty and deferred storm cost adjustments. Revised customer rates became effective on March 16, 2018.

On May 15, 2018, the Public Staff filed a Notice of Cross Appeal to the North Carolina Supreme Court from the February 23, 2018, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase issued by the NCUC. The Public Staff contend the commission’s order should be reversed and remanded, as it is affected by errors of law, and is unsupported by competent, material and substantial evidence in view of the entire record as submitted. The North Carolina Attorney General and Sierra Club have also filed Notices of Appeal to the North Carolina Supreme Court from the February 23, 2018, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase. On November 29, 2018, the North Carolina Attorney General's Office filed a motion with the North Carolina Supreme Court requesting the court consolidate the Duke Energy Progress and Duke Energy Carolinas appeals and enter an order adopting the parties’ proposed briefing schedule as set out in the filing. On November 29, 2018, the North Carolina Supreme Court adopted a schedule for briefing set forth in the motion to consolidate the Duke Energy Progress and Duke Energy Carolinas appeals. The Appellee response briefs are due July 29, 2019. Duke Energy Progress cannot predict the outcome of this matter.

2016 South Carolina Rate Case

In December 2016, the PSCSC approved a rate case settlement agreement among the ORS, intervenors and Duke Energy Progress. Terms of the settlement agreement included an approximate $56 million increase in revenues over a two-year period. An increase of approximately $38 million in revenues was effective January 1, 2017, and an additional increase of approximately $19 million in revenues was effective January 1, 2018. Duke Energy Progress amortized approximately $19 million from the cost of removal reserve in 2017. Other settlement terms included a rate of return on equity of 10.1 percent, recovery of coal ash costs incurred from January 1, 2015, through June 30, 2016, over a 15-year period and ongoing deferral of allocated ash basin closure costs from July 1, 2016, until the next base rate case. The settlement also provides that Duke Energy Progress will not seek an increase in rates in South Carolina to occur prior to 2019, with limited exceptions.

2018 South Carolina Rate Case

On November 8, 2018, Duke Energy Progress filed an application with the PSCSC for a rate increase for retail customers of approximately $59 million, which represents an approximate 10.3 percent increase in annual base revenues. The rate increase is driven by capital investments and environmental compliance progress made by Duke Energy Progress since its previous rate case, including the further implementation of Duke Energy Progress’ generation modernization program, which consists of retiring, replacing and upgrading generation plants, investments in customer service technologies and continued investments in base work to maintain its transmission and distribution systems. The request includes net tax benefits of $15 million consisting of a $12 million increase due to the expiration of EDITs related to reductions in North Carolina state income taxes allocable to South Carolina and decreases resulting from the Tax Act of $17 million to reflect the change in ongoing tax expense, primarily the reduction in the federal income tax rate from 35 to 21 percent, and $10 million to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change.

Duke Energy Progress also requested approval of its proposed Grid Improvement Plan, approval of a Prepaid Advantage Program and a variety of accounting orders related to ongoing costs for environmental compliance, including recovery over a five-year period of $51 million of deferred coal ash related compliance costs, AMI deployment, grid investments between rate changes and regulatory asset treatment related to the retirement of a generating plant located in Asheville, North Carolina. Finally, Duke Energy Progress sought approval to establish a reserve and accrual for end of life nuclear costs for materials and supplies and nuclear fuel. An evidentiary hearing is scheduled to begin on April 11, 2019, and a decision and revised customer rates are expected by mid-2019. Duke Energy Progress cannot predict the outcome of this matter.

Western Carolinas Modernization Plan

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

On March 28, 2016, the NCUC issued an order approving a CPCN for the new combined-cycle natural gas plants, but denying the CPCN for the contingent simple cycle unit without prejudice to Duke Energy Progress to refile for approval in the future. On March 28, 2018, Duke Energy Progress filed an annual progress report for the construction of the combined-cycle plants with the NCUC, with an estimated cost of $893 million. Site preparation activities for the combined-cycle plants are complete and construction of these plants began in 2017, with an expected in-service date in late 2019.

On October 8, 2018, Duke Energy Progress filed an application with the NCUC for a CPCN to construct the Hot Springs Microgrid Solar and Battery Storage Facility. On November 30, 2018, the NCUC issued an order scheduling hearings, requiring filing of testimony, establishing discovery guidelines and requiring public notice. On February 7, 2019, Duke Energy Progress made a joint filing with the Public Staff, which accepted the Public Staff's proposed conditions and requested that the NCUC cancel the evidentiary hearing. Duke Energy Progress cannot predict the outcome of this matter.

The carrying value of the 376-MW Asheville coal-fired plant, including associated ash basin closure costs, of $327 million and $385 million is included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2018, and 2017, respectively. Duke Energy Progress' request for a regulatory asset at the time of retirement with amortization over a 10-year period was approved by the NCUC on February 23, 2018.

Shearon Harris Nuclear Plant Expansion

In 2006, Duke Energy Progress selected a site at Harris to evaluate for possible future nuclear expansion. On February 19, 2008, Duke Energy Progress filed its COL application with the NRC for two Westinghouse AP1000 reactors at Harris, which the NRC docketed for review. On May 2, 2013, Duke Energy Progress filed a letter with the NRC requesting the NRC to suspend its review activities associated with the COL at the Harris site. The NCUC and PSCSC approved deferral of retail costs. Total deferred costs are approximately $43 million as of December 31, 2018, and are recorded in Regulatory assets on Duke Energy Progress' Consolidated Balance Sheets. On November 17, 2016, the FERC approved Duke Energy Progress' rate recovery request filing for the wholesale ratepayers' share of the abandonment costs, including a debt-only return to be recovered through revised formula rates and amortized over a 15-year period beginning May 1, 2014. As part of the settlement agreement for the 2017 North Carolina Rate Case discussed above, Duke Energy Progress will amortize the regulatory asset over an eight-year period. NCUC approved the settlement on February 23, 2018.

South Carolina Petitions

On June 22, 2018, Duke Energy Progress filed a petition with the PSCSC seeking an accounting order authorizing Duke Energy Progress to adopt new depreciation rates, effective March 16, 2018, that reflect the results of Duke Energy Progress' most recent depreciation study. Also on June 22, 2018, Duke Energy Progress filed a petition with the PSCSC requesting an accounting order to defer certain costs incurred in connection with the deployment of AMI, the ongoing deployment of Duke Energy Progress' new billing and Customer Information System, new depreciation rates and costs incurred in connection with the return of certain excess deferred state income taxes from North Carolina. These requests totaling approximately $20 million were approved on July 25, 2018.

FERC Form 1 Reporting Matter

On October 18, 2017, Fayetteville Public Works Commission (FPWC) filed with FERC a complaint against Duke Energy Progress. In the complaint, FPWC alleges that Duke Energy Progress' change in its method of reporting materials and supplies inventory on FERC Form 1 for 2015 constituted a change in accounting practice that Duke Energy Progress was not permitted to implement without first obtaining FERC approval. On April 23, 2018, FERC issued an order finding that Duke Energy Progress' new reporting methodology was not proper and required Duke Energy Progress to revise its FERC Form 1s beginning in 2014 and to issue refunds to formula rate customers. Duke Energy Progress estimates that these refunds will total approximately $14 million. On May 23, 2018, Duke Energy Progress filed a request for rehearing alleging that FERC's order is incorrect. Duke Energy Progress revised its FERC Form 1 filings in June 2018. On August 31, 2018, Duke Energy Progress filed with FERC a refund report memorializing its payment of refunds to FPWC. Duke Energy Progress cannot predict the outcome of this matter.

Tax Act

As ordered by the NCUC on October 5, 2018, Duke Energy Progress filed a proposal on October 25, 2018, to adjust rates to reflect the reduction in federal corporate income tax rate from 35 to 21 percent for taxable years beginning after December 31, 2017, as outlined in the Tax Act. Duke Energy Progress proposed that this rate decrement be effective for service rendered on and after December 1, 2018. On November 28, 2018, the NCUC approved the proposal to implement the change in the federal corporate income tax rate and effective December 1, 2018, Duke Energy Progress implemented the rate reduction. Also, as ordered by the NCUC on October 5, 2018, Duke Energy Progress shall continue to hold in a deferred regulatory liability account the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act for the period January 1, 2018 through November 30, 2018. The disposition of such regulatory liability may be considered in Duke Energy Progress' next general rate case proceeding or in three years, whichever is sooner. EDIT related to the corporate income tax rate reduction shall be held in a deferred tax regulatory liability account until they can be addressed for ratemaking purposes in the next general rate case proceeding or in three years, whichever is sooner.

Duke Energy Florida

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash[c]	**$ 10**	$ 9		(b)
AROs – nuclear and other[c]	**172**	296		(b)
Accrued pension and OPEB[c]	**532**	476	X	(g)
Retired generation facilities[c]	**219**	216	X	(b)
Storm cost deferrals[c][h]	**382**	376	(e)	2021
Nuclear asset securitized balance, net	**1,093**	1,142		2036
Hedge costs deferrals	**20**	30		2020
DSM/EE[c]	**21**	17	X	2023
Deferred fuel and purchased power[c]	**203**	219	(f)	2020
AMI[c]	**60**	75	X	2032
Other	**176**	36	(d)	(b)
Total regulatory assets	**2,888**	2,892		
Less: current portion	**434**	389		
Total noncurrent regulatory assets	**$ 2,454**	$ 2,503		
Regulatory Liabilities[a]				
Costs of removal[c]	**$ 257**	$ 415	(d)	(b)
Net regulatory liability related to income taxes[c]	**847**	948		(b)
Accrued pension and OPEB	**56**	—	X	(g)
Deferred fuel and purchased power[c]	**16**	—	(f)	2020

Other		**20**	18	(d)	(b)
Total regulatory liabilities		**1,196**	1,381		
Less: current portion		**102**	74		
Total noncurrent regulatory liabilities	**$**	**1,094** $	1,307		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Certain costs earn a return.
(e) Earns a debt return/interest once collections begin.
(f) Earns commercial paper rate.
(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.
(h) Balance includes $165 million for Hurricane Michael. Duke Energy Florida expects to seek recovery of these costs in the first half of 2019.

Storm Restoration Cost Recovery

In September 2017, Duke Energy Florida's service territory suffered significant damage from Hurricane Irma, resulting in approximately 1 million customers experiencing outages. In the fourth quarter of 2017, Duke Energy Florida also incurred preparation costs related to Hurricane Nate. On December 28, 2017, Duke Energy Florida filed a petition with the FPSC to recover incremental storm restoration costs for Hurricane Irma and Hurricane Nate and to replenish the storm reserve. On February 6, 2018, the FPSC approved a stipulation that would apply tax savings resulting from the Tax Act toward storm costs effective January 2018 in lieu of implementing a storm surcharge. Storm costs are currently expected to be fully recovered by approximately mid-2021. On May 31, 2018, Duke Energy Florida filed a petition for approval of actual storm restoration costs and associated recovery process related to Hurricane Irma and Hurricane Nate. The petition is seeking the approval for the recovery in the amount of $510 million in actual recoverable storm restoration costs, including the replenishment of Duke Energy Florida's storm reserve of $132 million, and the process for recovering these recoverable storm costs. On August 20, 2018, the FPSC approved Duke Energy Florida's unopposed Motion for Continuance filed August 17, 2018, to allow for an evidentiary hearing in this matter. On January 28, 2019, Duke Energy Florida made a supplemental filing to reduce the total storm cost recovery from $510 million to $508 million. The commission has scheduled the hearing to begin on May 21, 2019. At December 31, 2018, Duke Energy Florida's Consolidated Balance Sheets included approximately $217 million of recoverable costs under the FPSC's storm rule in Regulatory assets within Current Assets and Other Noncurrent Assets related to storm recovery for Hurricane Irma and Hurricane Nate. Duke Energy Florida cannot predict the outcome of this matter.

In October 2018, Duke Energy Florida's service territory suffered damage when Hurricane Michael made landfall as a strong Category 4 hurricane with maximum sustained winds of 155 mph. The storm caused catastrophic damage from wind and storm surge, particularly from Panama City Beach to Mexico Beach, resulting in widespread outages and significant damage to transmission and distribution facilities across the central Florida Panhandle. In response to Hurricane Michael, Duke Energy Florida restored service to approximately 72,000 customers. Duke Energy Florida incurred approximately $200 million of costs resulting from the hurricane restoration efforts. Approximately $35 million of the costs are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2018. The remaining $165 million of costs represent recoverable costs under the FPSC's storm rule and Duke Energy Florida's Open Access Transmission Tariff formula rates and are included in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2018. Duke Energy Florida anticipates filing a petition with the FPSC in the first half of 2019 to recover these costs, consistent with the provisions in the 2017 Settlement. Duke Energy Florida cannot predict the outcome of this matter.

Tax Act

Pursuant to Duke Energy Florida's 2017 Settlement, on May 31, 2018, Duke Energy Florida filed a petition related to the Tax Act, which included revenue requirement impacts of annual tax savings of $134 million and estimated annual amortization of EDIT of $67 million for a total of $201 million. Of this amount, $50 million would be offset by accelerated depreciation of Crystal River 4 and 5 coal units and an estimated $151 million would be offset by Hurricane Irma storm cost recovery as explained in the Storm Restoration Cost Recovery section above. On December 27, 2018, Duke Energy Florida filed actual EDIT balances and amortization based on its 2017 filed tax return. This increased the revenue requirement impact of the amortization of EDIT by $4 million, from $67 million to $71 million. On January 8, 2019, the FPSC approved a joint motion by Duke Energy Florida and the Office of Public Counsel resolving all stipulated positions. As part of that stipulation, Duke Energy Florida will seek a Private Letter Ruling from the IRS on its treatment of COR as mostly protected by tax normalization rules. If the IRS rules that COR is not protected by tax normalization rules, then Duke Energy Florida will make a final adjustment to the amortization of EDIT and an adjustment to the storm recovery amount retroactive to January 2018. Duke Energy Florida cannot predict the outcome of this matter.

Citrus County CC

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. At that time, the estimated cost of the facility was $1.5 billion, including AFUDC. On May 5, 2015, the Florida Department of Environmental Protection approved Duke Energy Florida's Site Certification Application and construction began in October 2015. On July 10, 2018, the FPSC approved Duke Energy Florida's request to include the annual revenue requirement of $200 million for the new Citrus County combined-cycle units in base rates. The first 820-MW power block came on-line on October 26, 2018, and the rate increase for this unit was effective in December 2018. The second 820-MW power block came on-line November 24, 2018. The rate increase for the second unit was effective in January 2019. The ultimate cost of the facility is estimated to be $1.6 billion, and Duke Energy Florida recorded Impairment charges on Duke Energy's Consolidated Statements of Operations of $60 million in the fourth quarter of 2018 for the overrun, which may change in light of recoveries from the EPC contractor. The plant began receiving natural gas from the Sabal Trail pipeline in August 2018. As a result of the combined-cycle natural gas plant coming on-line, Crystal River coal-fired units 1 and 2 were retired in December 2018. See Note 5 for additional information on Citrus.

Solar Base Rate Adjustment

On July 31, 2018, Duke Energy Florida petitioned the FPSC to include in base rates the revenue requirements for its first two solar generation projects, the Hamilton Project and the Columbia Project, as authorized by the 2017 Settlement. The Hamilton Project, which was placed into service on December 22, 2018, has an annual retail revenue requirement of $15 million and the increase was effective in January 2019. The Columbia Project has a projected annual revenue requirement of $14 million and a projected in-service date in early 2020; the associated rate increase would take place with the first month's billing cycle after the Columbia Project goes into service. At its October 30, 2018, Agenda Conference, the FPSC approved the rate increase related to the Hamilton Project to go into effect beginning with the first billing cycle in January 2019 under its file and suspend authority. Rates are subject to true up pending the outcome of the final hearing, which is scheduled to take place on April 2, 2019. Duke Energy Florida cannot predict the outcome of this matter.

Duke Energy Ohio

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash	**$ 20**	$ 17	X	(b)
Accrued pension and OPEB	**146**	139		(g)
Storm cost deferrals	**4**	5		2023
Hedge costs deferrals	**5**	6		(b)
DSM/EE	**10**	18	(f)	(e)
Grid modernization	**31**	39	X	(e)
Vacation accrual	**5**	5		2019
Deferred fuel and purchased power	**2**	—		2019
PISCC and deferred operating expenses[c]	**17**	19	X	2083
Transmission expansion obligation	**43**	50		(e)
MGP	**99**	91		(b)
AMI	**46**	6		(b)
East Bend deferrals	**47**	45	X	(b)
Deferred pipeline integrity costs	**14**	12	X	(b)

Other		**75**		42	(b)
Total regulatory assets		**564**		494	
Less: current portion		**33**		49	
Total noncurrent regulatory assets	**$**	**531**	$	445	
Regulatory Liabilities(a)					
Costs of removal	**$**	**126**	$	189	(d)
Net regulatory liability related to income taxes		**678**		688	(b)
Accrued pension and OPEB		**18**		16	(g)
Other		**75**		34	(b)
Total regulatory liabilities		**897**		927	
Less: current portion		**57**		36	
Total noncurrent regulatory liabilities	**$**	**840**	$	891	

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Recovered via a rider mechanism.
(f) Includes incentives on DSM/EE investments.
(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.

2017 Electric Security Plan

On June 1, 2017, Duke Energy Ohio filed with the PUCO a request for a standard service offer in the form of an ESP. On February 15, 2018, the procedural schedule was suspended to facilitate ongoing settlement discussions. On April 13, 2018, Duke Energy Ohio filed a Motion to consolidate this proceeding with several other cases currently pending before the PUCO, including, but not limited to, its Electric Base Rate Case. Additionally, on April 13, 2018, Duke Energy Ohio, along with certain intervenors, filed a Stipulation and Recommendation (Stipulation) with the PUCO resolving certain issues in this proceeding. The term of the ESP would be from June 1, 2018, to May 31, 2025, and includes continuation of market-based customer rates through competitive procurement processes for generation, continuation and expansion of existing rider mechanisms and proposed new rider mechanisms relating to regulatory mandates, costs incurred to enhance the customer experience and transform the grid and a service reliability rider for vegetation management. The Stipulation establishes a regulatory model for the next seven years via the approval of the ESP and continues the current model for procuring supply for non-shopping customers, including recovery mechanisms. On December 19, 2018, the PUCO approved the Stipulation without material modification. Several parties have filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. Duke Energy Ohio cannot predict the outcome of this matter.

Electric Base Rate Case

Duke Energy Ohio filed with the PUCO an electric distribution base rate case application and supporting testimony in March 2017. Duke Energy Ohio requested an estimated annual increase of approximately $15 million and a return on equity of 10.4 percent. The application also included requests to continue certain current riders and establish new riders. On September 26, 2017, the PUCO staff filed a report recommending a revenue decrease between approximately $18 million and $29 million and a return on equity between 9.22 percent and 10.24 percent. On April 13, 2018, Duke Energy Ohio filed a Motion to consolidate this proceeding with several other cases pending before the PUCO. On April 13, 2018, Duke Energy Ohio, along with certain intervenors, filed the Stipulation with the PUCO resolving numerous issues including those in this base rate proceeding. Major components of the Stipulation related to the base distribution rate case include a $19 million decrease in annual base distribution revenue with a return on equity unchanged from the current rate of 9.84 percent based upon a capital structure of 50.75 percent equity and 49.25 percent debt. Upon approval of new rates, Duke Energy Ohio's rider for recovering its initial SmartGrid implementation ends as these costs will be recovered through base rates. The Stipulation also renews 14 existing riders, some of which were included in the company's ESP, and adds two new riders including the Enhanced Service Reliability Rider to recover vegetation management costs not included in base rates, up to $10 million per year (operation and maintenance only) and the PowerForward Rider to recover costs incurred to enhance the customer experience and further transform the grid (operation and maintenance and capital). In addition to the changes in revenue attributable to the Stipulation, Duke Energy Ohio's capital-related riders, including the Distribution Capital Investments Rider, began to reflect the lower federal income tax rate associated with the Tax Act with updates to customers' bills beginning April 1, 2018. This change reduces electric revenue by approximately $20 million on an annualized basis. On December 19, 2018, the PUCO approved the Stipulation without material modification. New base rates were implemented effective January 2, 2019. Several parties have filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. Duke Energy Ohio cannot predict the outcome of this matter.

Ohio Valley Electric Corporation

On March 31, 2017, Duke Energy Ohio filed for approval to adjust its existing price stabilization rider (Rider PSR), which is currently set at zero dollars, to pass through net costs related to its contractual entitlement to capacity and energy from the generating assets owned by OVEC. Duke Energy Ohio sought deferral authority for net costs incurred from April 1, 2017, until the new rates under Rider PSR are put into effect. On April 13, 2018, Duke Energy Ohio filed a Motion to consolidate this proceeding with several other cases currently pending before the PUCO. Also on April 13, 2018, Duke Energy Ohio, along with certain intervenors, filed a Stipulation with the PUCO resolving numerous issues including those related to Rider PSR. The Stipulation activates Rider PSR for recovery of net costs incurred from January 1, 2018 through May 2025. On December 19, 2018, the PUCO approved the Stipulation without material modification. Several parties have filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. Duke Energy Ohio cannot predict the outcome of this matter. See Note 17 for additional discussion of Duke Energy Ohio's ownership interest in OVEC.

Tax Act – Ohio

On July 25, 2018, Duke Energy Ohio filed an application to establish a new rider to implement the benefits of the Tax Act for electric distribution customers. Duke Energy Ohio requested commission approval to implement the rider effective October 1, 2018, as a credit to all distribution customers based upon a percent reduction to Duke Energy Ohio’s distribution rates. The new rider will flow through to customers the benefit of the lower statutory federal tax rate from 35 to 21 percent since January 1, 2018, all future benefits of the lower tax rates and a full refund of deferred income taxes collected at the higher tax rates in prior years. Deferred income taxes subject to normalization rules will be refunded consistent with federal law and deferred income taxes not subject to normalization rules will be refunded over a 10-year period. Duke Energy Ohio's transmission rates reflect lower federal income tax but guidance from FERC on amortization of both protected and unprotected transmission-related EDITs is still pending. On October 24, 2018, the PUCO issued a Finding and Order that, among other things, directed all utilities over which the commission has rate-making authority to file an application to pass the benefits of the Tax Act to customers by January 1, 2019, unless otherwise exempted or directed by the PUCO. Duke Energy Ohio's July 25, 2018, filing for electric distribution operations is consistent with the commission's October 24, 2018, Finding and Order and no further action is needed. On February 20, 2019, the PUCO approved the application without material modification. Rates will be effective March 1, 2019. On December 21, 2018, Duke Energy Ohio filed an application to change its base rates and establish a new rider to implement the benefits of the Tax Act for natural gas customers. Duke Energy Ohio requested commission approval to implement the changes and rider effective April 1, 2019. The new rider will flow through to customers the benefit of the lower statutory federal tax rate from 35 to 21 percent since January 1, 2018, all future benefits of the lower tax rates and a full refund of deferred income taxes collected at the higher tax rates in prior years. Deferred income taxes subject to normalization rules will be refunded consistent with federal law and deferred income taxes not subject to normalization rules will be refunded over a 10-year period. The PUCO has not yet ruled on the application for changes for natural gas customers. 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. The PUCO approved Duke Energy Ohio’s application but found that Duke Energy Ohio was not permitted to use banked energy savings from previous years in order to calculate the amount of allowed incentive. This conclusion represented a change to the cost recovery mechanism that had been agreed upon by intervenors and approved by the PUCO in previous cases. The PUCO granted the applications for rehearing filed by Duke Energy Ohio and an intervenor. On January 6, 2016, Duke Energy Ohio and the PUCO Staff entered into a stipulation, pending the PUCO's approval, to resolve issues related to performance incentives and the PUCO Staff audit of 2013 costs, among other issues. In December 2015, based upon the stipulation, Duke Energy Ohio re-established approximately $20 million of the revenues that had been previously reversed. On October 26, 2016, the PUCO issued an order approving the stipulation without modification. In December 2016, the PUCO granted the intervenors request for rehearing for the purpose of further review. Duke Energy Ohio cannot predict the outcome of this matter.

On June 15, 2016, Duke Energy Ohio filed an application for approval of a three-year energy efficiency and peak demand reduction portfolio of programs. A stipulation and modified stipulation were filed on December 22, 2016, and January 27, 2017, respectively. Under the terms of the stipulations, which included support for deferral authority of all costs and a cap on shared savings incentives, Duke Energy Ohio has offered its energy efficiency and peak demand reduction programs throughout 2017. On February 3, 2017, Duke Energy Ohio filed for deferral authority of its costs incurred in 2017 in respect of its proposed energy efficiency and peak demand reduction portfolio. On September 27, 2017, the PUCO issued an order approving a modified stipulation. The modifications impose an annual cap of approximately $38 million on program costs and shared savings incentives combined, but allowed for Duke Energy Ohio to file for a waiver of costs in excess of the cap in 2017. The PUCO approved the waiver request for 2017 up to a total cost of $56 million. On November 21, 2017, the PUCO granted Duke Energy Ohio's and intervenor's applications for rehearing of the September 27, 2017, order. On January 10, 2018, the PUCO denied the Ohio Consumers' Counsel’s application for rehearing of the PUCO order granting Duke Energy Ohio's waiver request; however, a decision on Duke Energy Ohio's application for rehearing remains pending. 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 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 (Rider DCI) 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. On March 21, 2018, the PUCO issued an order denying Duke Energy Ohio's issues on rehearing. On April 20, 2018, Duke Energy Ohio filed a second application for rehearing based upon the commission’s March 21, 2018, Order. On May 16, 2018, the commission issued its third Entry on Rehearing granting in part, and denying in part, Duke Energy Ohio’s rehearing request.

On March 9, 2018, Duke Energy Ohio filed a motion to extend its then-current ESP, including all terms and conditions thereof, pending approval of a new ESP. On May 30, 2018, the PUCO granted the request, with modification. Specifically, the PUCO did not extend the cap applicable to Rider DCI beyond July 31, 2018. Duke Energy Ohio sought rehearing of this finding. On July 25, 2018, the PUCO granted the request and allowed a continuing cap on recovery under Rider DCI. On August 24, 2018, OMA and OCC filed an Application for Rehearing of the commission's decision. Duke Energy Ohio filed a Memorandum Contra OCC's request for rehearing of the commission's continuation of Rider DCI on September 4, 2018. On September 19, 2018, the PUCO issued an Order granting rehearing on the matter for further consideration. Duke Energy Ohio cannot predict the outcome of this matter.

On May 21, 2018, the Ohio Manufacturers' Association (OMA) filed a notice of appeal of PUCO's approval of Duke Energy Ohio’s ESP with the Ohio Supreme Court, challenging PUCO's approval of Duke Energy Ohio’s Price Stability Rider as a placeholder and its Rider DCI to recover incremental revenue requirement for distribution capital since Duke Energy Ohio’s last base rate case. On July 16, 2018, the Office of the Ohio Consumers' Counsel (OCC) filed its own appeal of Duke Energy Ohio’s ESP with the Ohio Supreme Court raising similar issues to that of the OMA. Duke Energy Ohio filed a Motion to Intervene in the two Ohio Supreme Court appeals. OMA's Supreme Court brief was filed on August 20, 2018. PUCO submitted its brief on October 26, 2018, and Duke Energy Ohio filed its brief on October 29, 2018. The OCC’s Supreme Court brief was filed on October 15, 2018. Duke Energy Ohio filed its brief on December 20, 2018. The PUCO submitted its brief on December 21, 2018. Duke Energy Ohio cannot predict the outcome of this matter.

Natural Gas Pipeline Extension

Duke Energy Ohio is proposing to install a new natural gas pipeline (the Central Corridor Project) in its Ohio service territory to increase system reliability and enable the retirement of older infrastructure. Duke Energy Ohio currently estimates the pipeline development costs and construction activities will range from $163 million to $245 million in direct costs (excluding overheads and AFUDC). On January 20, 2017, Duke Energy Ohio filed an amended application with the Ohio Power Siting Board (OPSB) for approval of one of two proposed routes. A public hearing was held on June 15, 2017. In April 2018, Duke Energy Ohio filed a motion with OPSB to establish a procedural schedule and filed supplemental information supporting its application. On December 18, 2018, the OPSB established a procedural schedule that includes a local public hearing on March 21, 2019, and an evidentiary hearing starting on April 9, 2019. If approved, construction of the pipeline extension is expected to be completed before the 2021/2022 winter season. Duke Energy Ohio cannot predict the outcome of this matter.

2012 Natural Gas Rate Case/MGP Cost Recovery

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

The PUCO order also contained conditional deadlines for completing the MGP environmental investigation and remediation costs at the MGP sites. As of December 31, 2018, Duke Energy Ohio had approximately $24 million for future remediation costs expected to be incurred at the East End site and approximately $23 million for future remediation costs expected to be incurred at the West End site included in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets.

Duke Energy Kentucky Electric Rate Case

On September 1, 2017, Duke Energy Kentucky filed a rate case with the KPSC requesting an increase in electric base rates of approximately $49 million, which represents an approximate 15 percent increase on the average customer bill. Subsequent to the filing, Duke Energy Kentucky adjusted the requested amount to $30.1 million, in part to reflect the benefits of the Tax Act, representing an approximate 9 percent increase on the average customer bill. The rate increase was driven by increased investment in utility plant, increased operations and maintenance expenses and recovery of regulatory assets. The application also includes requests to implement an Environmental Surcharge Mechanism to recover environmental costs not recovered in base rates, to establish a Distribution Capital Investment Rider to recover incremental costs of specific programs, to establish a FERC Transmission Cost Reconciliation Rider to recover escalating transmission costs and to modify existing Profit Sharing Mechanism to increase customers' share of proceeds from the benefits of owning generation and to mitigate shareholder risks associated with that generation. An evidentiary hearing concluded on March 8, 2018, and the KPSC issued an order on April 13, 2018. Major components of the Order include approval of an $8 million increase in base rates with a return on equity at 9.725 percent based upon a capital structure of 49 percent equity on a total allocable capitalization of approximately $650 million. The Order approved the Environmental Surcharge Mechanism Rider and in June 2018 recovery began of capital-related environmental costs, including costs related to ash and ash disposal, and environmental operation and maintenance expenses formerly recovered in base rates, including expenses for environmental reagents and emission allowances. The incremental revenue from this rider will be approximately $13 million on an annualized basis. The order settles all issues associated with the Tax Act as it relates to the electric business by lowering the income tax component of the revenue requirement and refunding protected EDIT under allowable normalization rules and unprotected EDIT over 10 years. The Order denied requests to implement riders for certain transmission costs and distribution capital investments. Duke Energy Kentucky implemented new base rates on May 1, 2018. On May 3, 2018, Duke Energy Kentucky filed an application for rehearing on certain aspects of the order; on May 23, 2018, the KPSC granted a rehearing. On October 2, 2018, the KPSC issued its rehearing order correcting certain findings in its initial order and making additional changes that are immaterial to the company's earnings.

Duke Energy Kentucky Natural Gas Base Rate Case

On August 31, 2018, Duke Energy Kentucky filed an application with the KPSC requesting an increase in natural gas base rates of approximately $11 million, an approximate 11.1 percent average increase across all customer classes. The increase is net of approximately $5 million in annual savings as a result of the Tax Act. The drivers for this case are capital invested since Duke Energy Kentucky’s last rate case in 2009. Duke Energy Kentucky is also seeking implementation of a Weather Normalization Adjustment Mechanism, amortization of regulatory assets and to implement the impacts of the Tax Act, prospectively. On January 30, 2019, Duke Energy Kentucky entered into a settlement agreement with the Attorney General of Kentucky, the only intervenor in the case, which if approved would resolve the matter. The settlement provides for an approximate $7 million increase and approval of the proposed Weather Normalization Mechanism. A hearing was held on February 5, 2019. A ruling is expected in late first quarter 2019. Duke Energy Kentucky cannot predict the outcome of this matter.

FERC 494 Refund of Regional Transmission Enhancement Projects

FERC Order No. 494 Settlement Agreement (FERC 494 Settlement Agreement) was entered into by most of the PJM transmission owners, including Duke Energy Ohio and Duke Energy Kentucky, and the PJM state regulatory commissions approximately two years ago and was planned to be effective on January 1, 2016; however, it was not approved by FERC until May 31, 2018. The FERC 494 Settlement Agreement was due to the Seventh Circuit Court of Appeals finding that FERC had failed to adequately justify the costs that the customers in the western part of PJM were being charged for high voltage transmission projects, or Regional Transmission Expansion Plan (RTEP) projects (500 kV and above) built in the east. These costs were being allocated to all PJM customers on a load-ratio share basis but the court determined that these costs were not justifiable to customers in the west, including Duke Energy Ohio and Duke Energy Kentucky, that did not benefit from the RTEP projects. Costs for the periods 2012 through 2015 are expected to be refunded to Duke Energy Ohio and Duke Energy Kentucky on a monthly basis through December 2025. The refund amount for similar costs incurred beginning in 2016 through June 30, 2018, prior to the change in cost allocation by PJM was determined in the third quarter of 2018 and these amounts will be refunded over a 12-month period beginning in July 2018. These refunds, totaling approximately $47 million for Duke Energy Ohio and Duke Energy Kentucky, have been recorded to Operation, maintenance and other on the Consolidated Statements of Operations for the year ended December 31, 2018.

Regional Transmission Organization Realignment

Duke Energy Ohio, including Duke Energy Kentucky, transferred control of its transmission assets from MISO to PJM, effective December 31, 2011. The PUCO approved a settlement related to Duke Energy Ohio’s recovery of certain costs of the RTO realignment via a non-bypassable rider. Duke Energy Ohio is allowed to recover all MTEP costs directly or indirectly charged to Ohio customers. 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 recorded in Other within Current Liabilities and Other Noncurrent Liabilities on the Consolidated Balance Sheets. The retail portions of MTEP costs billed by MISO are recovered by Duke Energy Ohio through a non-bypassable rider. As of December 31, 2018, and 2017, $43 million and $50 million, respectively, are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets.

(in millions)	December 31, 2017	Provisions/ Adjustments	Cash Reductions	December 31, 2018
Duke Energy Ohio	$ 66	$ (4)	$ (4)	$ 58

Duke Energy Indiana

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	2018	2017	a Return	Period Ends
Regulatory Assets[(a)]				
AROs – coal ash	$ 450	$ 380		(b)
Accrued pension and OPEB	222	197		(f)
Retired generation facilities[(c)]	57	65	X	2026
Hedge costs deferrals	24	25		(b)
DSM/EE	14	21	(e)	(e)
Vacation accrual	11	11		2019
Deferred fuel and purchased power	40	18		2019
PISCC and deferred operating expenses[(c)]	233	274	X	(b)
AMI[(c)]	18	21	X	(b)
Other	88	131		(b)
Total regulatory assets	1,157	1,143		
Less: current portion	175	165		
Total noncurrent regulatory assets	$ 982	$ 978		
Regulatory Liabilities[(a)]				
Costs of removal	$ 628	$ 644		(d)
Net regulatory liability related to income taxes	1,009	998		(b)
Amounts to be refunded to customers	1	10		2019
Accrued pension and OPEB	67	64		(f)
Other	42	31		(b)
Total regulatory liabilities	1,747	1,747		
Less: current portion	25	24		
Total noncurrent regulatory liabilities	$ 1,722	$ 1,723		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.

(e) Includes incentives on DSM/EE investments and is recovered through a tracker mechanism over a two-year period.

(f) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.

FERC Transmission Return on Equity Complaint

Customer groups have filed with the FERC complaints against Midcontinent Independent System Operator, Inc. (MISO) and its transmission-owning members, including Duke Energy Indiana, alleging, among other things, that the current base rate of return on equity earned by MISO transmission owners of 12.38 percent is unjust and unreasonable. The complaints claim, among other things, that the current base rate of return on equity earned by MISO transmission owners should be reduced to 8.67 percent. On January 5, 2015, the FERC issued an order accepting the MISO transmission owners' adder of 0.50 percent to the base rate of return on equity based on participation in an RTO subject to it being applied to a return on equity that is shown to be just and reasonable in the pending return on equity complaints. On December 22, 2015, the presiding FERC ALJ in the first complaint issued an Initial Decision in which the base rate of return on equity was set at 10.32 percent. On September 28, 2016, the Initial Decision in the first complaint was affirmed by FERC, but is subject to rehearing requests. On June 30, 2016, the presiding FERC ALJ in the second complaint issued an Initial Decision setting the base rate of return on equity at 9.70 percent. The Initial Decision in the second complaint is pending FERC review. On April 14, 2017, the U.S. Court of Appeals for the District of Columbia Circuit, in *Emera Maine v. FERC*, reversed and remanded certain aspects of the methodology employed by FERC to establish rates of return on equity. On October 16, 2018, FERC issued an order in response to the Emera remand proceeding proposing a new method for determining whether an existing return on equity is unjust and unreasonable, and a new process for determining a just and reasonable return on equity. On November 14, 2018, FERC directed parties to the MISO complaints to file briefs on how the new process for determining return on equity proposed in the Emera proceeding should be applied to the complaints involving the MISO transmission owners’ return on equity. Initial briefs were filed on February 13, 2019, and reply briefs will be due April 10, 2019. Duke Energy Indiana currently believes these matters will not have a material impact on its results of operations, cash flows and financial position.

Benton County Wind Farm Dispute

On December 16, 2013, BCWF filed a lawsuit against Duke Energy Indiana seeking damages for past generation losses alleging Duke Energy Indiana violated its obligations under a 2006 PPA by refusing to offer electricity to the market at negative prices. Damage claims continue to increase during times that BCWF is not dispatched. Under 2013 revised MISO market rules, Duke Energy Indiana is required to make a price offer to MISO for the power it proposes to sell into MISO markets and MISO determines whether BCWF is dispatched. Because market prices would have been negative due to increased market participation, Duke Energy Indiana determined it would not bid at negative prices in order to balance customer needs against BCWF's need to run. BCWF contends Duke Energy Indiana must bid at the lowest negative price to ensure dispatch, while Duke Energy Indiana contends it is not obligated to bid at any particular price, that it cannot ensure dispatch with any bid and that it has reasonably balanced the parties' interests. On July 6, 2015, the U.S. District Court for the Southern District of Indiana entered judgment against BCWF on all claims. BCWF appealed the decision and on December 9, 2016, the appeals court ruled in favor of BCWF. Duke Energy Indiana recorded an obligation and a regulatory asset related to the settlement amount in fourth quarter 2016. On June 30, 2017, the parties finalized a settlement agreement. Terms of the settlement included Duke Energy Indiana paying $29 million for back damages. Additionally, the parties agreed on the method by which the contract will be bid into the market in the future. The settlement amount was paid in June 2017. The IURC issued an order on September 27, 2017, approving recovery of the settlement amount through Duke Energy Indiana's fuel clause. The IURC order has been appealed to the Indiana Court of Appeals. On May 21, 2018, the Indiana Court of Appeals upheld the commission's decision. The appellants have requested rehearing at the Indiana Court of Appeals. The Indiana Court of Appeals denied the request for rehearing. The appellants have requested transfer to the Indiana Supreme Court, including briefs in support from environmental groups. The Indiana Supreme Court denied transfer concluding this matter in favor of Duke Energy Indiana.

Edwardsport Integrated Gasification Combined Cycle Plant

On September 20, 2018, Duke Energy Indiana, the Indiana Office of Utility Consumer Counselor, the Duke Industrial Group and Nucor Steel – Indiana entered into a settlement agreement to resolve IGCC ratemaking issues for calendar years 2018 and 2019. The agreement will remain in effect until new rates are established in Duke Energy Indiana's next base rate case, which is expected to be filed in mid-2019 with rates effective in mid-2020. It addresses the pending Edwardsport filing at the commission and eliminates the need for future filings until the overall rate case. This settlement includes caps on Duke Energy Indiana’s retail operating expenses for 2018 and 2019, reduces Duke Energy Indiana's regulatory asset by $30 million (with a corresponding reduction of the amount of amortization of the regulatory asset included in rates by $10 million annually beginning with the implementation of final IGCC 17 rates), and provides funding for low-income assistance and clean energy projects. Duke Energy Indiana recognized pretax impairment and related charges of $32 million in the third quarter of 2018. The settlement is subject to IURC approval. An evidentiary hearing was held December 2018 and an IURC Order is expected in March 2019. Duke Energy Indiana cannot predict the outcome of this matter.

Tax Act

On June 27, 2018, Duke Energy Indiana, the Indiana Office of Utility Consumer Counselor, the Indiana Industrial Group and Nucor Steel – Indiana filed testimony consistent with their Stipulation and Settlement Agreement (Settlement Agreement) in the federal tax act proceeding with the IURC. The Settlement Agreement outlines how Duke Energy Indiana will implement the impacts of the Tax Act. Material components of the Settlement Agreement were as follows:

- Riders to reflect the change in the statutory federal tax rate from 35 to 21 percent as they are filed in 2018;
- Base rates to reflect the change in the statutory federal tax rate from 35 to 21 percent upon IURC approval, but no later than September 1, 2018;
- Duke Energy Indiana to continue to defer protected federal EDIT until January 1, 2020, at which time it will be returned to customers according to the Average Rate Assumption Method required by the Internal Revenue Service over approximately 26 years; and
- Duke Energy Indiana to begin returning unprotected federal EDIT upon IURC approval, over 10 years. In order to mitigate the negative impacts to cash flow and credit metrics, the Settlement Agreement allows Duke Energy Indiana to return $7 million per year over the first five years, with a step up to $35 million per year in the following five years.

On August 22, 2018, the IURC approved the settlement and rates were adjusted effective September 1, 2018.

Piedmont

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2018**	**2017**	**a Return**	**Period Ends**
Regulatory Assets[(a)]				
AROs – other	**$ 19**	$ 15		(d)
Accrued pension and OPEB[(c)]	**99**	91	X	(f)
Derivatives – gas supply contracts[(e)]	**141**	142		
Vacation accrual	**12**	10		
Deferred pipeline integrity costs[(c)]	**51**	42	X	(b)
Amount due from customers	**24**	64	X	(b)
Other	**11**	14		(b)
Total regulatory assets	**357**	378		
Less: current portion	**54**	95		
Total noncurrent regulatory assets	**$ 303**	$ 283		
Regulatory Liabilities[(a)]				
Costs of removal	**$ 564**	$ 544		(d)
Net regulatory liability related to income taxes	**579**	597		(b)
Accrued pension and OPEB[(c)]	**1**	—	X	(f)
Amount due to customers	**33**	—	X	(b)
Other	**41**	3		(b)
Total regulatory liabilities	**1,218**	1,144		
Less: current portion	**37**	3		
Total noncurrent regulatory liabilities	**$ 1,181**	$ 1,141		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Balance will fluctuate with changes in the market. Current contracts extend into 2031.
(f) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 22 for additional detail.

South Carolina Rate Stabilization Adjustment Filing

On June 15, 2018, Piedmont filed with the PSCSC under the South Carolina Rate Stabilization Act its quarterly monitoring report for the 12-month period ending March 31, 2018. The filing included a revenue deficiency calculation and tariff rates in order to permit Piedmont the opportunity to earn the rate of return on common equity established in its last general rate case. The filing also incorporated the impacts of the Tax Act by lowering the income tax component of the revenue requirement, refunding protected EDIT under allowable normalization rules, unprotected EDIT and amounts over collected from the customers from January 1, 2018, through the end of the review period for this proceeding. A settlement agreement reached between Piedmont and ORS was filed with the PSCSC on September 14, 2018, and approved by the PSCSC on October 3, 2018. Terms of the settlement include implementation of rates for the 12-month period beginning November 2018 with a return on equity of 10.2 percent.

North Carolina Integrity Management Rider Filing

In October 2018, Piedmont filed a petition under the IMR mechanism to collect an additional $10 million in annual revenues, effective December 2018, based on the eligible capital investments closed to integrity and safety projects over the six-month period ended September 30, 2018. On November 27, 2018, the NCUC approved the requested rate adjustment.

In May 2018, Piedmont filed, and the NCUC approved, a petition under the IMR mechanism to update rates, effective June 2018, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending March 31, 2018, and the decrease in the corporate federal income tax rate effective January 1, 2018. The combined effect of the update was a reduction to annual revenues of approximately $6 million.

Tennessee Integrity Management Rider Filing

In November 2018, Piedmont filed a petition with the TPUC under the IMR mechanism to collect an additional $3 million in annual revenues, effective January 2019, based on the eligible capital investments closed to integrity and safety projects over the 12-month period ending October 31, 2018. A hearing on this matter is scheduled for March 2019.

2018 North Carolina Rate Case

On February 27, 2019, Piedmont filed a notice with the NCUC of its intent to file a base rate adjustment application no earlier than 30 days from the notice submittal date.

OTHER REGULATORY MATTERS

Progress Energy Merger FERC Mitigation

Since December 2014, the FERC Office of Enforcement has conducted an investigation of Duke Energy’s market power filings in its application for approval of the Progress Energy merger submitted in 2012. On June 8, 2018, the FERC issued an order approving a settlement agreement under which Duke Energy paid a penalty of $3.5 million. The FERC Office of Enforcement stated in its conclusion that Duke Energy violated FERC regulations by failing to fully and accurately describe certain specific matters in its market power filings. Duke Energy neither admitted nor denied the alleged violations.

Atlantic Coast Pipeline, LLC

On September 2, 2014, Duke Energy, Dominion Resources (Dominion), Piedmont and Southern Company Gas announced the formation of Atlantic Coast Pipeline, LLC (ACP) to build and own the proposed Atlantic Coast Pipeline (ACP pipeline), an approximately 600-mile interstate natural gas pipeline running from West Virginia to North Carolina. The ACP pipeline is designed to meet, in part, the needs identified by Duke Energy Carolinas, Duke Energy Progress and Piedmont. Dominion will be responsible for building and operating the ACP pipeline and holds a leading ownership percentage in ACP of 48 percent. Duke Energy owns a 47 percent interest, which is accounted for as an equity method investment through its Gas Utilities and Infrastructure segment. Southern Company Gas maintains a 5 percent interest. See Notes 12 and 17 for additional information related to Duke Energy's ownership interest. Duke Energy Carolinas, Duke Energy Progress and Piedmont, among others, will be customers of the pipeline. Purchases will be made under several 20-year supply contracts, subject to state regulatory approval.

In 2018, the FERC issued a series of Notices to Proceed, which authorized the project to begin certain construction-related activities along the pipeline route, including supply header and compressors. On May 11, 2018, and October 19, 2018, FERC issued Notices to Proceed allowing full construction activities in all areas of West Virginia except in the Monongahela National Forest. On July 24, 2018, FERC issued a Notice to Proceed allowing full construction activities along the project route in North Carolina. On October 19, 2018, the conditions to effectiveness of the Virginia 401 water quality certification were satisfied. Immediately following receipt of the Virginia 401 certification, ACP filed a request for FERC to issue a Notice to Proceed with full construction activities in Virginia. We appreciate the professional and collaborative process by the permitting agencies designed to ensure that this critical energy infrastructure project will meet the stringent environmental standards required by law and regulation.

ACP is the subject of challenges in state and federal courts and agencies, including, among others, challenges of the project's incidental take statement (ITS), crossings of the Blue Ridge Parkway, the Appalachian Trail, and the Monongahela and George Washington National Forests, the project's U.S. Army Corps of Engineers (USACE) 404 permit, the Virginia conditional 401 water quality certification, the FERC Environmental Impact Statement order and the FERC order approving the Certificate of Public Convenience and Necessity. Each of these challenges alleges non-compliance on the part of federal and state permitting authorities and adverse ecological consequences if the project is permitted to proceed. ACP is vigorously defending these challenges and coordinating with the federal and state authorities which are the direct parties to the challenges. Since July 2018, notable developments in these challenges include a stay issued by the U.S. Court of Appeals for the Fourth Circuit (Fourth Circuit) on construction activities through the Monongahela and George Washington National Forests, a reissuance of the project's ITS and Blue Ridge Parkway right-of-way and renewed challenges of these reissued permits, a stay issued by the Fourth Circuit of the project's biological opinion and ITS (which stay has halted most project construction activity), a Fourth Circuit decision vacating the project's permits to cross the Monongahela and George Washington National Forests and the Appalachian Trail and the Fourth Circuit's remand to USACE of ACP's Huntington District 404 verification.

The delays resulting from the legal challenges described above have impacted the cost and schedule for the project. As a result, project cost estimates have increased to $7.0 billion to $7.8 billion, excluding financing costs. ACP expects to achieve a late 2020 in-service date for key segments of the project, while it expects the remainder to extend into 2021. Abnormal weather, work delays (including delays due to judicial or regulatory action) and other conditions may result in cost or schedule modifications in the future.

Sabal Trail Transmission, LLC

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

On February 3, 2016, the FERC issued an order granting the request for a CPCN to construct and operate the pipeline. The Sabal Trail pipeline received other required regulatory approvals and the Phase 1 mainline was placed in service in July 2017. On October 12, 2017, Sabal Trail filed a request with FERC to place in-service a lateral line to Duke Energy Florida's Citrus County CC. This request is required to support commissioning and testing activities at the facility. On March 16, 2018, FERC approved the Citrus lateral and it was placed in service.

On September 21, 2016, intervenors filed an appeal of FERC's CPCN orders to the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals). On August 22, 2017, the appeals court ruled against FERC in the case for failing to include enough information on the impact of greenhouse-gas emissions carried by the pipeline, vacated the CPCN order and remanded the case to FERC. In response to the August 2017 court decision, the FERC issued a draft Supplemental Environmental Impact Statement (SEIS) on September 27, 2017. On October 6, 2017, FERC and a group of industry intervenors, including Sabal Trail and Duke Energy Florida, filed separate petitions with the D.C. Circuit Court of Appeals requesting rehearing regarding the court's decision to vacate the CPCN order. On January 31, 2018, the D.C. Circuit Court of Appeals denied the requests for rehearing. On February 2, 2018, Sabal Trail filed a request with FERC for expedited issuance of its order on remand and reissuance of the CPCN. In the alternative, the pipeline requested that FERC issue a temporary emergency CPCN to allow for continued operations. On February 5, 2018, FERC issued the final SEIS. On February 6, 2018, FERC and the intervenors in this case each filed motions for stay with the D.C. Circuit Court to stay the court's mandate. On March 7, 2018, the D.C. Circuit Court of Appeals granted FERC and Sabal Trail's stay request. On March 14, 2018, FERC issued its final order on remand, which recertified the project. On August 10, 2018, FERC denied requests for rehearing of the final order on remand.

Constitution Pipeline Company, LLC

Duke Energy owns a 24 percent ownership interest in Constitution, which is accounted for as an equity method investment. Constitution is a natural gas pipeline project slated to transport natural gas supplies from the Marcellus supply region in northern Pennsylvania to major northeastern markets. The pipeline will be constructed and operated by Williams Partners L.P., which has a 41 percent ownership share. The remaining interest is held by Cabot Oil and Gas Corporation and WGL Holdings, Inc. Before the permitting delays discussed below, Duke Energy's total anticipated contributions were approximately $229 million. As a result of the permitting delays and project uncertainty, total anticipated contributions by Duke Energy can no longer be reasonably estimated. Since April 2016, with the actions of the New York State Department of Environmental Conservation (NYSDEC), Constitution stopped construction and discontinued capitalization of future development costs until the project's uncertainty is resolved.

In December 2014, Constitution received approval from the FERC to construct and operate the proposed pipeline. However, on April 22, 2016, the NYSDEC denied Constitution's application for a necessary water quality certification for the New York portion of the Constitution pipeline. Constitution filed legal actions in the U.S. Court of Appeals for the Second Circuit (U.S. Court of Appeals) challenging the legality and appropriateness of the NYSDEC's decision and on August 18, 2017, the petition was denied in part and dismissed in part. In September 2017, Constitution filed a petition for a rehearing of portions of the decision unrelated to the water quality certification, which was denied by the U.S. Court of Appeals. In January 2018, Constitution petitioned the Supreme Court of the United States to review the U.S. Court of Appeals decision, and on April 30, 2018, the Supreme Court denied Constitution's petition. In October 2017, Constitution filed a petition for declaratory order requesting FERC to find that the NYSDEC waived its rights to issue a Section 401 water quality certification by not acting on Constitution's application within a reasonable period of time as required by statute. This petition was based on precedent established by another pipeline's successful petition with FERC following a District of Columbia Circuit Court ruling. On January 11, 2018, FERC denied Constitution's petition. In February 2018, Constitution filed a rehearing request with FERC of its finding that the NYSDEC did not waive the Section 401 certification requirement. On July 19, 2018, FERC denied Constitution's rehearing request. Constitution is currently unable to approximate an in-service date for the project due to the NYSDEC's denial of the water quality certification. The Constitution partners remain committed to the project and are evaluating next steps to move the project forward. On June 25, 2018, Constitution filed with FERC a Request for Extension of Time until December 2, 2020, for construction of the project. On November 5, 2018, FERC issued an Order Granting Extension of Time.

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

Potential Coal Plant Retirements

The Subsidiary Registrants periodically file IRPs 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. IRPs filed by the Subsidiary Registrants included planning assumptions to potentially retire certain coal-fired generating facilities in North Carolina and Indiana earlier than their current estimated useful lives primarily because facilities do not have the requisite emission control equipment to meet regulatory requirements expected to apply in the near future. Duke Energy continues to evaluate the potential need to retire these coal-fired generating facilities earlier than the current estimated useful lives and plans to seek regulatory recovery for amounts that would not be otherwise recovered when any of these assets are retired.

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, 2018, 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**	**$ 162**
Duke Energy Indiana		
Gallagher Units 2 and 4[(b)]	**280**	**121**
Total Duke Energy	**865**	**$ 283**

(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 committed to either retire or stop burning coal at Gallagher Units 2 and 4 by December 31, 2022, as part of the 2016 settlement of Edwardsport IGCC matters.

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

5. COMMITMENTS AND CONTINGENCIES

INSURANCE

General Insurance

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

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

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

Nuclear Insurance

Duke Energy Carolinas owns and operates McGuire and Oconee and operates and has a partial ownership interest in 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 Robinson, Brunswick and Harris. Robinson and Harris each have one reactor. Brunswick has two reactors.

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

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

Nuclear Liability Coverage

The Price-Anderson Act requires owners of nuclear reactors to provide for public nuclear liability protection per nuclear incident up to a maximum total financial protection liability. The maximum total financial protection liability, which is approximately $14.1 billion, is subject to change every five years for inflation and for the number of licensed reactors. Total nuclear liability coverage consists of a combination of private primary nuclear liability insurance coverage and a mandatory industry risk-sharing program to provide for excess nuclear liability coverage above the maximum reasonably available private primary coverage. The U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims.

Primary Liability Insurance

Duke Energy Carolinas and Duke Energy Progress have purchased the maximum reasonably available private primary nuclear liability insurance as required by law, which is $450 million per station. Duke Energy Florida has purchased $100 million primary nuclear liability insurance in compliance with the law.

Excess Liability Program

This program provides $13.6 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 $138 million times the current 99 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 $20.5 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 NEIL, an industry mutual insurance company, which provides property damage, nuclear accident decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Additionally, NEIL provides accidental outage coverage for each station for losses in the event of a major accidental outage at an insured nuclear station.

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

Losses resulting from acts of terrorism are covered as common occurrences, such that if terrorist acts occur against one or more commercial nuclear power plants insured by NEIL within a 12-month period, they would be treated as one event and the owners of the plants where the act occurred would share one full limit of liability. The full limit of liability is currently $3.2 billion. NEIL sublimits the total aggregate for all of their policies for non-nuclear terrorist events to approximately $1.8 billion.

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

NEIL’s Accidental Outage policy provides some coverage, such as business interruption, for losses in the event of a major accident property damage outage of a nuclear unit. Coverage is provided on a weekly limit basis after a significant waiting period deductible and at 100 percent of the available weekly limits for 52 weeks and 80 percent of the available weekly limits for the next 110 weeks. Coverage is provided until these available weekly periods are met where the accidental outage policy limit will not exceed $490 million for McGuire, Catawba and Harris, $476 million for Brunswick, $462 million for Oconee and $392 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 $159 million, $97 million and $1 million, respectively. Duke Energy Carolinas' maximum assessment amount includes 100 percent of potential obligations to NEIL for jointly owned reactors. Duke Energy Carolinas would seek reimbursement from the joint owners for their portion of these assessment amounts.

ENVIRONMENTAL

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

Remediation Activities

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

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

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Balance at December 31, 2015	$ 94	$ 10	$ 17	$ 3	$ 14	$ 54	$ 12
Provisions/adjustments	19	4	7	2	4	7	1
Cash reductions	(15)	(4)	(6)	(2)	(4)	(2)	(3)
Balance at December 31, 2016	98	10	18	3	14	59	10
Provisions/adjustments	8	3	3	2	2	3	(4)
Cash reductions	(25)	(3)	(6)	(2)	(4)	(15)	(1)
Balance at December 31, 2017	81	10	15	3	12	47	5
Provisions/adjustments	**26**	**3**	**2**	**3**	**(2)**	**21**	**1**
Cash reductions	**(30)**	**(2)**	**(6)**	**(2)**	**(4)**	**(20)**	**(1)**
Balance at December 31, 2018	**$ 77**	**$ 11**	**$ 11**	**$ 4**	**$ 6**	**$ 48**	**$ 5**

As of December 31, 2016, and October 31, 2016 and 2015, Piedmont's environmental reserve was $1 million. As of December 31, 2018, and 2017, the reserve was $2 million.

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	**$ 46**
Duke Energy Carolinas	**17**
Duke Energy Ohio	**19**
Piedmont	**2**

North Carolina and South Carolina Ash Basins

In February 2014, a break in a stormwater pipe beneath an ash basin at Duke Energy Carolinas' retired Dan River Steam Station caused a release of ash basin water and ash into the Dan River. In July 2014, Duke Energy completed remediation work identified by the EPA and continues to cooperate with the EPA's civil enforcement process. The NCDEQ has historically assessed Duke Energy Carolinas and Duke Energy Progress with NOVs 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 Sutton and Dan River Steam Station. Duke Energy Carolinas and Duke Energy Progress continue to resolve violations through corrective actions, and associated penalties related to existing unresolved NOVs are not expected to be material.

LITIGATION

Duke Energy Carolinas and Duke Energy Progress

Coal Ash Insurance Coverage Litigation

In March 2017, Duke Energy Carolinas and Duke Energy Progress filed a civil action in the North Carolina Superior Court against various insurance providers. The lawsuit seeks payment for coal ash-related liabilities covered by third-party liability insurance policies. The insurance policies were issued between 1971 and 1986 and provide third-party liability insurance for property damage. The civil action seeks damages for breach of contract and indemnification for costs arising from the Coal Ash Act and the EPA CCR rule at 15 coal-fired plants in North Carolina and South Carolina. On January 23, 2019, the court granted the parties' joint motion for a four month stay of the proceedings, until June 3, 2019, to allow the parties to discuss potential resolution. If the case is not fully resolved at that time, litigation will resume. The trial remains scheduled for August 2020. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

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 coal-fired power plants in North Carolina. The NCDEQ filed enforcement actions against Duke Energy Carolinas and Duke Energy Progress alleging violations of water discharge permits and North Carolina groundwater standards. The cases have been consolidated and are being heard before a single judge in the North Carolina Superior Court.

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

The court issued orders in 2016 granting Motions for Partial Summary Judgment for seven of the 14 North Carolina plants with coal ash basins named in the enforcement actions. On February 13, 2017, the court issued an order denying motions for partial summary judgment brought by both the environmental groups and Duke Energy Carolinas and Duke Energy Progress for the remaining seven plants. On March 15, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Notice of Appeal with the North Carolina Court of Appeals to challenge the trial court's order. The parties were unable to reach an agreement at mediation in April 2017 and submitted briefs to the trial court on remaining issues to be tried. On August 1, 2018, the Court of Appeals dismissed the appeal and the matter is proceeding before the trial court. No trial date has been scheduled. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

Federal Citizens Suits

On June 13, 2016, RRBA filed a federal citizen suit in the Middle District of North Carolina alleging unpermitted discharges to surface water and groundwater violations at the Mayo Plant. On August 19, 2016, Duke Energy Progress filed a Motion to Dismiss. On April 26, 2017, the court entered an order dismissing four of the claims in the federal citizen suit. Two claims relating to alleged violations of NPDES permit provisions survived the motion to dismiss, and Duke Energy Progress filed its response on May 10, 2017. Duke Energy Progress and RRBA each filed motions for summary judgment on March 23, 2018. The court has not yet ruled on these motions.

On May 16, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina, which asserts two claims relating to alleged violations of NPDES permit provisions at the Roxboro Plant and one claim relating to the use of nearby water bodies. Duke Energy Progress and RRBA each filed motions for summary judgment on April 17, 2018, and the court has not yet ruled on these motions.

On May 8, 2018, on motion from Duke Energy Progress, the court ordered trial in both of the above matters to be consolidated. Trial is currently scheduled to begin July 15, 2019.

On June 20, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina challenging the closure plans at the Mayo Plant under the EPA CCR Rule. Duke Energy Progress filed a motion to dismiss, which was granted by the court on March 30, 2018. RRBA had until April 30, 2018, to file an appeal to the Fourth Circuit but did not do so.

On August 2, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina challenging the closure plans at the Roxboro Plant under the EPA CCR Rule. Duke Energy Progress filed a motion to dismiss on October 2, 2017, which was granted by the court on May 29, 2018. RRBA had until June 28, 2018, to file an appeal to the Fourth Circuit but did not do so.

On December 5, 2017, various parties filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina for alleged violations at Duke Energy Carolinas' Belews Creek under the CWA. Duke Energy Carolinas' answer to the complaint was filed on August 27, 2018. On October 10, 2018, Duke Energy Carolinas filed Motions to Dismiss for lack of standing, Motion for Judgment on the Pleadings and Motion to Stay Discovery. On January 9, 2019, the court entered an order denying Duke Energy Carolinas' motion to stay discovery. There has been no ruling on the other pending motions.

Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of these matters.

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 DHHS. Results of CSAs testing performed by Duke Energy under the Coal Ash Act have been consistent with historical data provided to state regulators over many years. The DHHS and NCDEQ sent follow-up letters on October 15, 2015, to residents near coal ash basins who have had their wells tested, stating that private well samplings at a considerable distance from coal ash basins, as well as some municipal water supplies, contain similar levels of vanadium and hexavalent chromium, which led investigators to believe these constituents are naturally occurring. In March 2016, DHHS rescinded the advisories.

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

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

On September 14, 2017, a complaint was filed against Duke Energy Progress in New Hanover County Superior Court by a group of homeowners residing approximately 1 mile from Duke Energy Progress' Sutton Steam Plant. The homeowners allege that coal ash constituents have been migrating from ash impoundments at Sutton into their groundwater for decades and that in 2015, Duke Energy Progress discovered these releases of coal ash, but failed to notify any officials or neighbors and failed to take remedial action. The homeowners claim unspecified physical and mental injuries as a result of consuming their well water and seek actual damages for personal injury, medical monitoring and punitive damages. On March 6, 2018, Plaintiffs' counsel voluntarily dismissed the action without prejudice.

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, 2018, there were 164 asserted claims for non-malignant cases with the cumulative relief sought of up to $42 million and 87 asserted claims for malignant cases with the cumulative relief sought of up to $21 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 $630 million and $489 million at December 31, 2018, and 2017, respectively. These reserves are classified in Other within Other Noncurrent Liabilities and Other within Current Liabilities on the Consolidated Balance Sheets. These reserves are based upon Duke Energy Carolinas' best estimate for current and future asbestos claims through 2038 and are recorded on an undiscounted basis. 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 2038 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 $764 million in excess of the self-insured retention. Receivables for insurance recoveries were $739 million and $585 million at December 31, 2018, and 2017, respectively. These amounts are classified in Other within Other Noncurrent Assets and Receivables within Current Assets on the Consolidated Balance Sheets. Duke Energy Carolinas is not aware of any uncertainties regarding the legal sufficiency of insurance claims. Duke Energy Carolinas believes the insurance recovery asset is probable of recovery as the insurance carrier continues to have a strong financial strength rating.

Duke Energy Progress and Duke Energy Florida

Spent Nuclear Fuel Matters

On October 16, 2014, Duke Energy Progress and Duke Energy Florida sued the U.S. in the U.S. Court of Federal Claims. The lawsuit claimed the Department of Energy breached a contract in failing to accept spent nuclear fuel under the Nuclear Waste Policy Act of 1982 and asserted damages for the cost of on-site storage. Duke Energy Progress and Duke Energy Florida asserted damages for the period January 1, 2011, through December 31, 2013, of $48 million and $25 million, respectively. On November 17, 2017, the Court awarded Duke Energy Progress and Duke Energy Florida $48 million and $21 million, respectively, subject to appeal. No appeals were filed and Duke Energy Progress and Duke Energy Florida recognized the recoveries in the first quarter of 2018. Claims for all periods through 2013 have been resolved. On June 22, 2018, Duke Energy Progress and Duke Energy Florida filed a complaint for damages incurred for 2014 through first quarter 2018.

Duke Energy Progress

Gypsum Supply Agreements Matter

On June 30, 2017, CertainTeed filed a declaratory judgment action against Duke Energy Progress in the North Carolina Business Court relating to a gypsum supply agreement. In its complaint, CertainTeed sought an order from the court declaring that the minimum amount of gypsum Duke Energy Progress must provide to CertainTeed under the supply agreement was 50,000 tons per month through 2029. Trial in this matter was completed on July 16, 2018. On August 29, 2018, the court issued an order and opinion finding that Duke Energy Progress is required to supply 50,000 tons of gypsum/month, but that CertainTeed's sole remedy for Duke Energy Progress' long-term discontinuance under the agreement is liquidated damages. On November 14, 2018, the parties reached a settlement agreement. The amount owed under the liquidated damages provision is approximately $90 million on an undiscounted basis over 10 years. Approximately $3 million was paid in 2018. As of December 31, 2018, $9 million is recorded in Accounts payable within Current Liabilities and $63 million in Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets. The liability is recorded on a discounted basis at a rate of approximately 4 percent. These costs are probable of recovery from customers and are recorded in Regulatory Assets within Other Noncurrent Assets on the Consolidated Balance Sheets.

Duke Energy Florida

Fluor Contract Litigation

On January 29, 2019, Fluor filed a breach of contract lawsuit in the U.S. District Court for the Middle District of Florida against Duke Energy Florida related to an EPC agreement for the combined-cycle natural gas plant in Citrus County, Florida. Fluor filed an amended complaint on February, 13, 2019. Fluor's multicount complaint seeks civil, statutory and contractual remedies related to Duke Energy Florida's $67 million draw in early 2019, on Fluor's letter of credit and offset of invoiced amounts. Duke Energy Florida is attempting to recover from Fluor $110 million in additional costs incurred by Duke Energy Florida. Duke Energy Florida cannot predict the outcome of this matter. See Note 4 for additional information.

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 class of Duke Energy Florida and FP&L's customers in Florida. The suit alleges the State of Florida's NCRS are unconstitutional and pre-empted by federal law. Plaintiffs claim they are entitled to repayment of all money paid by customers of Duke Energy Florida and FP&L as a result of the NCRS, as well as an injunction against any future charges under those statutes. The constitutionality of the NCRS has been challenged unsuccessfully in a number of prior cases on alternative grounds. Duke Energy Florida and FP&L filed motions to dismiss the complaint on May 5, 2016. On September 21, 2016, the Court granted the motions to dismiss with prejudice. Plaintiffs filed a motion for reconsideration, which was denied. On January 4, 2017, plaintiffs filed a notice of appeal to the Eleventh Circuit U.S. Court of Appeals (Eleventh Circuit). On July 11, 2018, the Eleventh Circuit affirmed the U.S. District Court's dismissal of the lawsuit. The deadline to file a petition for cert was October 9, 2018, and no petition was filed; therefore, the dismissal of the lawsuit is final.

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 an EPC for Levy as well as a determination by the court of the amounts due to Westinghouse as a result of the termination of an EPC contract. Duke Energy Florida recognized an exit obligation as a result of the termination of the EPC. On March 31, 2014, Westinghouse filed a separate lawsuit against Duke Energy Florida in U.S. District Court for the Western District of Pennsylvania alleging damages under the same EPC contract 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, granting Westinghouse a $30 million termination fee claim and dismissing Duke Energy Florida's $54 million refund claim. Westinghouse's claim for termination costs continued to trial. Following a trial on the matter, the court issued an order in December 2016 denying Westinghouse's claim for termination costs and reaffirming its earlier ruling in favor of Westinghouse on the $30 million termination fee. Judgment was entered against Duke Energy Florida in the amount of approximately $34 million, which includes prejudgment interest. Westinghouse appealed the trial court's order to the Fourth Circuit and Duke Energy Florida cross-appealed.

On March 29, 2017, Westinghouse filed Chapter 11 bankruptcy in the Southern District of New York, which automatically stayed the appeal. On May 23, 2017, the bankruptcy court entered an order lifting the stay with respect to the appeal. Westinghouse and Duke Energy Florida executed a settlement agreement resolving this matter on April 5, 2018. The bankruptcy court approved the settlement and Duke Energy Florida paid approximately $34 million to Westinghouse in July 2018 pursuant to this agreement. At the request of the parties, the Fourth Circuit has dismissed the appeal.

MGP Cost Recovery Action

On December 30, 2011, Duke Energy Florida filed a lawsuit against FirstEnergy to recover investigation and remediation costs incurred by Duke Energy Florida in connection with the restoration of two former MGP sites in Florida. Duke Energy Florida alleged that FirstEnergy, as the successor to Associated Gas & Electric Co., owes past and future contribution and response costs of up to $43 million for the investigation and remediation of MGP sites. On December 6, 2016, the trial court entered judgment against Duke Energy Florida in the case. In January 2017, Duke Energy Florida appealed the decision to the U.S. Court of Appeals for the Sixth Circuit, which affirmed the trial court's ruling on April 10, 2018. The dismissal of the lawsuit is therefore final.

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, the CertainTeed liquidated damages obligation and the exit obligation in 2017 related to the termination of an EPC contract. Reserves are classified on the Consolidated Balance Sheets in Other within Other Noncurrent Liabilities 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)	**2018**	**2017**
Reserves for Legal Matters		
Duke Energy	**$ 65**	$ 88
Duke Energy Carolinas	**9**	30
Progress Energy	**54**	55
Duke Energy Progress	**12**	13
Duke Energy Florida	**24**	24
Piedmont	**1**	2

OTHER COMMITMENTS AND CONTINGENCIES

General

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

Purchase Obligations

Purchased Power

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

The following table presents executory purchased power contracts with terms exceeding one year, excluding contracts classified as leases.

		Minimum Purchase Amount at December 31, 2018						
(in millions)	**Contract Expiration**	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Duke Energy Progress[a]	2022-2031	$ 51	$ 52	$ 53	$ 30	$ 25	$ 215	$ 426
Duke Energy Florida[b]	2021-2025	363	380	365	363	382	361	2,214
Duke Energy Ohio[c][d]	2020-2022	146	117	53	11	—	—	327

(a) Contracts represent 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 8 percent of net plant output.
(d) Excludes PPA with OVEC. See Note 17 for additional information.

Gas Supply and Capacity Contracts

Duke Energy Ohio and Piedmont routinely enter into long-term natural gas supply commodity and capacity commitments and other agreements that commit future cash flows to acquire services needed in their businesses. These commitments include pipeline and storage capacity contracts and natural gas supply contracts to provide service to customers. Costs arising from the natural gas supply commodity and capacity commitments, while significant, are pass-through costs to customers and are generally fully recoverable through the fuel adjustment or PGA procedures and prudence reviews in North Carolina and South Carolina and under the Tennessee Incentive Plan in Tennessee. In the Midwest, these costs are recovered via the Gas Cost Recovery Rate in Ohio or the Gas Cost Adjustment Clause in Kentucky. The time periods for fixed payments under pipeline and storage capacity contracts are up to 16 years. The time periods for fixed payments under natural gas supply contracts are up to seven years. The time period for the natural gas supply purchase commitments is up to 12 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, 2018.

(in millions)	**Duke Energy**	**Duke Energy Ohio**	**Piedmont**
2019	**$ 314**	**$ 38**	**$ 276**
2020	**287**	**30**	**257**
2021	**255**	**29**	**226**
2022	**225**	**11**	**214**
2023	**148**	**4**	**144**
Thereafter	**1,067**	**—**	**1,067**
Total	**$ 2,296**	**$ 112**	**$ 2,184**

Operating and Capital Lease Commitments

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

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

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Duke Energy	**$ 268**	$ 241	$ 242
Duke Energy Carolinas	**49**	44	45
Progress Energy	**143**	130	140
Duke Energy Progress	**75**	75	68
Duke Energy Florida	**68**	55	72
Duke Energy Ohio	**13**	15	16
Duke Energy Indiana	**21**	23	23

	Years Ended December 31,		Two Months Ended December 31,	Year Ended October 31,
(in millions)	**2018**	**2017**	**2016**	**2016**
Piedmont	**$ 11**	$ 7	$ 1	$ 5

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

	December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
2019	**$ 239**	**$ 33**	**$ 97**	**$ 49**	**$ 48**	**$ 2**	**$ 6**	**$ 5**
2020	**219**	**29**	**90**	**46**	**44**	**2**	**5**	**5**
2021	**186**	**19**	**79**	**37**	**42**	**2**	**4**	**5**
2022	**170**	**19**	**76**	**34**	**42**	**2**	**4**	**5**
2023	**160**	**17**	**77**	**35**	**42**	**2**	**5**	**6**

Thereafter	1,017	68	455	314	141	23	66	11
Total	$ 1,991	$ 185	$ 874	$ 515	$ 359	$ 33	$ 90	$ 37

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

	December 31, 2018						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
2019	$ 170	$ 20	$ 45	$ 20	$ 25	$ 2	$ 1
2020	174	20	46	21	25	—	1
2021	177	15	45	20	25	—	1
2022	165	15	45	21	24	—	1
2023	165	15	45	21	24	—	1
Thereafter	577	204	230	209	21	—	27
Minimum annual payments	1,428	289	456	312	144	2	32
Less: amount representing interest	(487)	(180)	(205)	(175)	(30)	—	(22)
Total	$ 941	$ 109	$ 251	$ 137	$ 114	$ 2	$ 10

6. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	December 31, 2018								
(in millions)	Weighted Average Interest Rate	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured debt, maturing 2019-2078	4.26%	$ 20,955	$ 1,150	$ 3,800	$ 50	$ 350	$ 1,000	$ 408	$ 2,150
Secured debt, maturing 2020-2037	3.69%	4,297	450	1,703	300	1,403	—	—	—
First mortgage bonds, maturing 2019-2048[a]	4.32%	25,628	8,759	13,100	7,574	5,526	1,099	2,670	—
Capital leases, maturing 2019-2051[b]	5.06%	941	109	251	137	114	2	10	—
Tax-exempt bonds, maturing 2019-2041[c]	3.40%	941	243	48	48	—	77	572	—
Notes payable and commercial paper[d]	2.73%	4,035	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	739	1,385	444	108	299	317	198
Fair value hedge carrying value adjustment		5	5	—	—	—	—	—	—
Unamortized debt discount and premium, net[e]		1,434	(23)	(29)	(15)	(11)	(31)	(8)	(1)
Unamortized debt issuance costs[f]		(297)	(54)	(112)	(40)	(61)	(7)	(20)	(11)
Total debt	4.13%	$ 57,939	$ 11,378	$ 20,146	$ 8,498	$ 7,429	$ 2,439	$ 3,949	$ 2,336
Short-term notes payable and commercial paper		(3,410)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(439)	(1,235)	(294)	(108)	(274)	(167)	(198)

Current maturities of long-term debt(g)	(3,406)	(6)	(1,672)	(603)	(270)	(551)	(63)	(350)
Total long-term debt(g)	$ 51,123 $	10,933 $	17,239 $	7,601 $	7,051 $	1,614 $	3,719 $	1,788

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $63 million and $531 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, letters of credit or the Master Credit Facility.
(d) Includes $625 million that was classified as Long-Term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities that backstop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted average days to maturity for Duke Energy's commercial paper program was 16 days.
(e) Duke Energy includes $1,380 million and $156 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $41 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(g) Refer to Note 17 for additional information on amounts from consolidated VIEs.

	December 31, 2017								
(in millions)	Weighted Average Interest Rate	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured debt, maturing 2018-2073	4.17%	$ 20,409 $	1,150 $	3,950 $	— $	550 $	900 $	411 $	2,050
Secured debt, maturing 2018-2037	3.15%	4,458	450	1,757	300	1,457	—	—	—
First mortgage bonds, maturing 2018-2047(a)	4.51%	23,529	7,959	11,801	6,776	5,025	1,100	2,669	—
Capital leases, maturing 2018-2051(b)	4.55%	1,000	61	269	139	129	5	11	—
Tax-exempt bonds, maturing 2019-2041(c)	3.23%	941	243	48	48	—	77	572	—
Notes payable and commercial paper(d)	1.57%	2,788	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	404	955	390	—	54	311	364
Fair value hedge carrying value adjustment		6	6	—	—	—	—	—	—
Unamortized debt discount and premium, net(e)		1,582	(19)	(30)	(16)	(10)	(33)	(9)	(1)
Unamortized debt issuance costs(f)		(271)	(47)	(108)	(40)	(56)	(7)	(21)	(12)
Total debt	4.09%	$ 54,442 $	10,207 $	18,642 $	7,597 $	7,095 $	2,096 $	3,944 $	2,401
Short-term notes payable and commercial paper		(2,163)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(104)	(805)	(240)	—	(29)	(161)	(364)
Current maturities of long-term debt(g)		(3,244)	(1,205)	(771)	(3)	(768)	(3)	(3)	(250)
Total long-term debt(g)		$ 49,035 $	8,898 $	17,066 $	7,354 $	6,327 $	2,064 $	3,780 $	1,787

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.

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

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, 2018
Unsecured Debt				
Progress Energy	March 2019	7.050%	$	450
Duke Energy (Parent)	September 2019	5.050%		500
Piedmont	September 2019	3.155% (b)		350
Duke Energy Kentucky	October 2019	4.65%		100
Progress Energy	December 2019	4.875%		350
First Mortgage Bonds				
Duke Energy Progress	January 2019	5.300%		600
Duke Energy Ohio	April 2019	5.450%		450
Other(a)				606
Current maturities of long-term debt			$	3,406

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

Maturities and Call Options

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

	December 31, 2018						
	Duke	Duke Energy	Progress	Duke Energy	Duke Energy	Duke Energy	Duke Energy

(in millions)	Energy[a]	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
2019	$ 3,408	$ 6	$ 1,674	$ 603	$ 270	552	$ 63	$ 350
2020	3,765	907	926	354	572	—	503	—
2021	4,803	503	2,004	904	600	50	70	160
2022	2,745	353	1,032	505	77	—	94	—
2023	3,375	1,303	535	456	79	350	153	45
Thereafter	35,288	7,940	12,880	5,437	5,793	1,251	2,925	1,595
Total long-term debt, including current maturities	$ 53,384	$ 11,012	$ 19,051	$ 8,259	$ 7,391	$ 2,203	$ 3,808	$ 2,150

(a) Excludes $1,578 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, 2018				
(in millions)	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Ohio	Duke Energy Indiana
Tax-exempt bonds	$ 312	$ —	$ —	$ 27	$ 285
Commercial paper[a]	625	300	150	25	150
Total	$ 937	$ 300	$ 150	$ 52	$ 435

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

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

Summary of Significant Debt Issuances

In January 2019, Duke Energy Ohio issued $800 million of first mortgage bonds. The issuance was split between a $400 million, 10-year tranche at 3.65 percent and a $400 million, 30-year tranche at 4.30 percent. The net proceeds will be used to refinance $450 million of Duke Energy Ohio bonds maturing in April 2019, to pay down short-term debt and for general corporate purposes.

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

			Year Ended December 31, 2018				
Issuance Date	**Maturity Date**	**Interest Rate**	**Duke Energy**	**Duke Energy (Parent)**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Florida**
Unsecured Debt							
March 2018[(a)]	April 2025	3.950%	$ 250	$ 250	$ —	$ —	$ —
May 2018[(b)]	May 2021	3.114%	500	500	—	—	—
September 2018[(c)]	September 2078	5.625%	500	500	—	—	—
First Mortgage Bonds							
March 2018[(d)]	March 2023	3.050%	500	—	500	—	—
March 2018[(d)]	March 2048	3.950%	500	—	500	—	—
June 2018[(e)]	July 2028	3.800%	600	—	—	—	600
June 2018[(e)]	July 2048	4.200%	400	—	—	—	400
August 2018[(f)]	September 2023	3.375%	300	—	—	300	—
August 2018[(f)]	September 2028	3.700%	500	—	—	500	—
November 2018[(g)]	May 2022	3.350%	350	—	350	—	—
November 2018[(g)]	November 2028	3.950%	650	—	650	—	—
Total issuances			$ 5,050	$ 1,250	$ 2,000	$ 800	$ 1,000

(a) Debt issued to pay down short-term debt.

(b) Debt issued to pay down short-term debt. Debt issuance has a floating debt rate.

(c) Callable after September 2023 at par. Junior subordinated hybrid debt issued to pay down short-term debt and for general corporate purposes.

(d) Debt issued to repay at maturity a $300 million first mortgage bond due April 2018, pay down intercompany short-term debt and for general corporate purposes.

(e) Debt issued to repay a portion of intercompany short-term debt under the money pool borrowing arrangement and for general corporate purposes.

(f) Debt issued to repay short-term debt and for general corporate purposes.

(g) Debt issued to fund eligible green energy projects, including zero-carbon solar and energy storage, in the Carolinas.

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

(a) Proceeds were used to refinance $400 million of unsecured debt at maturity and to repay a portion of outstanding commercial paper.

(b) Debt issued to repay a portion of outstanding commercial paper.
(c) Debt issued to repay at maturity $700 million of unsecured debt, to repay outstanding commercial paper and for general corporate purposes.
(d) Debt issued to fund storm restoration costs related to Hurricane Irma and for general corporate purposes.
(e) Portfolio financing of four Texas and Oklahoma wind facilities. Duke Energy pledged substantially all of the assets of these wind facilities and is nonrecourse to Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures.
(f) Portfolio financing of eight solar facilities located in California, Colorado and New Mexico. Duke Energy pledged substantially all of the assets of these solar facilities and is nonrecourse to Duke Energy. Proceeds were used to reimburse Duke Energy for a portion of previously funded construction expenditures.
(g) Debt issued to fund capital expenditures for ongoing construction and capital maintenance, to repay a $250 million aggregate principal amount of bonds at maturity and for general corporate purposes.
(h) Proceeds were used to fund capital expenditures for ongoing construction, capital maintenance and for general corporate purposes.
(i) Debt issued to repay at maturity a $200 million aggregate principal amount of bonds at maturity, pay down intercompany short-term debt and for general corporate purposes, including capital expenditures.
(j) Debt issued to refinance $400 million aggregate principal amount of bonds due January 2018, pay down intercompany short-term debt and for general corporate purposes.
(k) Principal balance will be repaid in equal quarterly installments beginning in March 2018.
(l) Debt issuance has a floating interest rate.

Available Credit Facilities

In January 2018, Duke Energy extended the termination date of substantially all of its existing $8 billion Master Credit Facility capacity from March 16, 2022, to March 16, 2023. In May 2018, Duke Energy completed the extension process with 100 percent of all commitments to the Master Credit Facility extending to March 16, 2023. The Duke Energy Registrants, excluding Progress Energy (Parent), have borrowing capacity under the Master Credit Facility up to specified sublimits for each borrower. Duke Energy has the unilateral ability at any time to increase or decrease the borrowing sublimits of each borrower, subject to a maximum sublimit for each borrower. The amount available under the Master Credit Facility has been reduced to backstop issuances of commercial paper, certain letters of credit and variable-rate demand tax-exempt bonds that may be put to the Duke Energy Registrants at the option of the holder. Duke Energy Carolinas and Duke Energy Progress are also required to each maintain $250 million of available capacity under the Master Credit Facility as security to meet obligations under plea agreements reached with the U.S. Department of Justice in 2015 related to violations at North Carolina facilities with ash basins.

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

	December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy (Parent)**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Facility size[a]	**$ 8,000**	**$ 2,650**	**$ 1,750**	**$ 1,400**	**$ 650**	**$ 450**	**$ 600**	**$ 500**
Reduction to backstop issuances								
Commercial paper[b]	**(3,022)**	**(917)**	**(739)**	**(444)**	**(108)**	**(299)**	**(317)**	**(198)**
Outstanding letters of credit	**(53)**	**(45)**	**(4)**	**(2)**	**—**	**—**	**—**	**(2)**
Tax-exempt bonds	**(81)**	**—**	**—**	**—**	**—**	**—**	**(81)**	**—**
Coal ash set-aside	**(500)**	**—**	**(250)**	**(250)**	**—**	**—**	**—**	**—**
Available capacity	**$ 4,344**	**$ 1,688**	**$ 757**	**$ 704**	**$ 542**	**$ 151**	**$ 202**	**$ 300**

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

Three-Year Revolving Credit Facility

Duke Energy (Parent) has a $1.0 billion revolving credit facility through June 2020. Borrowings under this facility will be used for general corporate purposes. As of December 31, 2018, $500 million has been drawn under the Three Year Revolver. This balance is classified as Long-term debt on Duke Energy's Consolidated Balance Sheets. Any undrawn commitments can be drawn, and borrowings can be prepaid, at any time throughout the term of the facility. The terms and conditions of the Three Year Revolver are generally consistent with those governing Duke Energy's Master Credit Facility.

Duke Energy Progress Term Loan Facility

In December 2018, Duke Energy Progress entered into a two-year term loan facility with commitments totaling $700 million. Borrowings under the facility will be used to pay storm-related costs, pay down commercial paper and to partially finance an upcoming bond maturity. As of December 31, 2018, $50 million has been drawn under the term loan. The balance is classified as Long-term debt on Duke Energy Progress' Consolidated Balance Sheets. In January and February 2019, the remaining $650 million was drawn under the term loan.

Piedmont Term Loan Facility

In September 2018, Piedmont executed an amendment to its existing senior unsecured term loan facility. The amendment increased commitments from $250 million to $350 million and extended the maturity date to September 2019. Borrowings under the facility will be used for general corporate purposes. As of December 31, 2018, the entire $350 million has been drawn under the Piedmont Term Loan. This balance is classified as Current maturities of long-term debt on Piedmont's Consolidated Balance Sheets. The terms and conditions of the Piedmont Term Loan are generally consistent with those governing Duke Energy's Master Credit Facility.

Other Debt Matters

In September 2016, Duke Energy filed a 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, 2018, and 2017 was $1,010 million and $986 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.

Money Pool

The Subsidiary Registrants, excluding Progress Energy (Parent), 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 (Parent), separately manage their cash needs and working capital requirements. Accordingly, there is no net settlement of receivables and payables between money pool participants. Duke Energy (Parent), may loan funds to its participating subsidiaries, but may not borrow funds through the money pool. Accordingly, as the money pool activity is between Duke Energy and its wholly owned subsidiaries, all money pool balances are eliminated within Duke Energy’s Consolidated Balance Sheets.

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

Restrictive Debt Covenants

The Duke Energy Registrants' debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65 percent for each borrower, excluding Piedmont, and 70 percent for Piedmont. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2018, each of the Duke Energy Registrants was in compliance with all covenants related to their debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Other Loans

As of December 31, 2018, and 2017, Duke Energy had loans outstanding of $741 million, including $37 million at Duke Energy Progress and $701 million, including $38 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 Other Noncurrent 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, standby 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, 2018, 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 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, 2018, 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, 2018, was $296 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, $248 million of the guarantees expire between 2019 and 2030, with the remaining performance guarantees having no contractual expiration.

In October 2017, ACP executed a $3.4 billion revolving credit facility with a stated maturity date of October 2021. Duke Energy entered into a guarantee agreement to support its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is $677 million as of December 31, 2018. This amount represents 47 percent of the outstanding borrowings under the credit facility.

Duke Energy guaranteed debt issued by Duke Energy Carolinas of $650 million as of December 31, 2018, and 2017.

Duke Energy has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a wholly owned and former non-wholly owned entity to honor its obligations to a third party. Under these arrangements, Duke Energy has payment obligations that are triggered by a draw by the third party or customer due to the failure of the wholly owned or former non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2018, Duke Energy had guaranteed $63 million of outstanding surety bonds, most of which have no set expiration.

Duke Energy uses bank-issued standby letters of credit to secure the performance of wholly owned and non-wholly owned entities to a third party or customer. Under these arrangements, Duke Energy has payment obligations to the issuing bank that are triggered by a draw by the third party or customer due to the failure of the wholly owned or non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2018, Duke Energy had issued a total of $454 million in letters of credit, which expire between 2019 and 2022. The unused amount under these letters of credit was $60 million.

Duke Energy recognized $23 million and $21 million, as of December 31, 2018, and 2017, respectively, primarily in Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets, for the guarantees discussed above. As current estimates change, additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded by the Duke Energy Registrants in the future.

8. JOINT OWNERSHIP OF GENERATING AND TRANSMISSION FACILITIES

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

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

	December 31, 2018			
(in millions except for ownership interest)	**Ownership Interest**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction Work in Progress**
Duke Energy Carolinas				
Catawba (units 1 and 2)[(a)]	**19.25%**	**$ 989**	**$ 483**	**$ 17**
W.S. Lee CC[(b)]	**86.67%**	**593**	**12**	**4**
Duke Energy Indiana				
Gibson (unit 5)[(c)]	**50.05%**	**390**	**173**	**3**
Vermillion[(d)]	**62.50%**	**168**	**135**	**—**
Transmission and local facilities[(c)]	**Various**	**5,037**	**1,769**	**—**

(a) Jointly owned with North Carolina Municipal Power Agency Number 1, NCEMC and PMPA.

(b) Jointly owned with NCEMC.
(c) Jointly owned with WVPA and Indiana Municipal Power Agency.
(d) Jointly owned with WVPA.

Effective June 30, 2018, Duke Energy Ohio, Ohio Power Company, and The Dayton Power and Light Company, completed an asset exchange that reallocated their ownership interest in certain jointly owned transmission facilities. This transaction was approved by FERC and PUCO. The transaction eliminated the joint owner relationships for these assets. Assets were exchanged at net book value and the net increase in Duke Energy Ohio's assets are shown within Capital expenditures in Duke Energy Ohio's Consolidated Statements of Cash Flows.

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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Decommissioning of nuclear power facilities[(a)]	$ 5,696	$ 2,335	$ 3,209	$ 2,679	$ 530	$ —	$ —	$ —
Closure of ash impoundments	4,446	1,568	2,123	2,103	20	52	702	—
Other[(b)]	325	46	79	38	41	41	20	19
Total asset retirement obligation	$ 10,467	$ 3,949	$ 5,411	$ 4,820	$ 591	$ 93	$ 722	$ 19
Less: current portion	919	290	514	509	5	6	109	—
Total noncurrent asset retirement obligation	$ 9,548	$ 3,659	$ 4,897	$ 4,311	$ 586	$ 87	$ 613	$ 19

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

Nuclear Decommissioning Liability

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

The following table summarizes information about the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs are stated in 2018 dollars for Duke Energy Carolinas, 2017 dollars for Duke Energy Florida and 2014 dollars for Duke Energy Progress, and include costs to decommission plant components not subject to radioactive contamination.

(in millions)	Annual Funding Requirement[a]	Decommissioning Costs[a]	Year of Cost Study
Duke Energy	$ 24	$ 8,737	2014 and 2018
Duke Energy Carolinas[b][c]	—	4,291	2018
Duke Energy Progress	24	3,550	2014
Duke Energy Florida[d]	—	896	2018

(a) Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida.
(b) Decommissioning cost for Duke Energy Carolinas reflects its ownership interest in jointly owned reactors. Other joint owners are responsible for decommissioning costs related to their interest in the reactors.
(c) Duke Energy Carolinas' site-specific nuclear decommissioning cost study completed in 2018 is expected to be filed with the NCUC and PSCSC by the second quarter 2019. Duke Energy Carolinas will also complete a new funding study, which will be completed and filed with the NCUC and PSCSC in 2019.
(d) Duke Energy Florida's site-specific nuclear decommissioning cost study and a new funding study were completed and filed with the FPSC in 2018.

Nuclear Decommissioning Trust Funds

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

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

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

	December 31,	
(in millions)	2018	2017
Duke Energy	$ 5,579	$ 5,864
Duke Energy Carolinas	3,133	3,321
Duke Energy Progress	2,446	2,543

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

The NRC has acknowledged permanent cessation of operation and permanent removal of fuel from the reactor vessel at Crystal River Unit 3. Therefore, the license no longer authorizes operation of the reactor. In January 2018, Crystal River Unit 3 reached a SAFSTOR status.

Closure of Ash Impoundments

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

The ARO amount recorded on the Consolidated Balance Sheets is based upon estimated closure costs for impacted ash impoundments. The amount recorded represents the discounted cash flows for estimated closure costs based upon either specific closure plans or the probability weightings of the potential closure methods as evaluated on a site-by-site basis. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from ash basins, consolidating material as necessary and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill or recycling the ash for concrete or some other beneficial use. The ultimate method and timetable for closure will be in compliance with standards set by federal and state regulations and other agreements. The ARO amount will be adjusted as additional information is gained through the closure and post-closure process, including acceptance and approval of compliance approaches, which may change management assumptions, and may result in a material change to the balance. See ARO Liability Rollforward section below for information on revisions made to the coal ash liability during 2018 and 2017.

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

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

ARO Liability Rollforward

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

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Balance at December 31, 2016	$ 10,611	$ 3,895	$ 5,475	$ 4,697	$ 778	$ 77	$ 866	$ 14
Accretion expense(a)	435	184	228	195	33	3	32	1
Liabilities settled(b)	(619)	(282)	(270)	(204)	(65)	(7)	(49)	(8)
Liabilities incurred in the current year(c)	51	5	—	—	—	7	29	8
Revisions in estimates of cash flows	(303)	(192)	(19)	(15)	(4)	4	(97)	—

Balance at December 31, 2017	10,175	3,610	5,414	4,673	742	84	781	15
Accretion expense(a)	**427**	**179**	**225**	**196**	**29**	**4**	**29**	**1**
Liabilities settled(b)	**(638)**	**(281)**	**(272)**	**(227)**	**(45)**	**(5)**	**(79)**	—
Liabilities incurred in the current year(c)	**39**	**8**	**5**	**—**	**5**	**—**	**25**	—
Revisions in estimates of cash flows(d)	**464**	**433**	**39**	**178**	**(140)**	**10**	**(34)**	**3**
Balance at December 31, 2018	**$ 10,467**	**$ 3,949**	**$ 5,411**	**$ 4,820**	**$ 591**	**$ 93**	**$ 722**	**$ 19**

(a) Substantially all accretion expense for the years ended December 31, 2018, and 2017 relates to Duke Energy's regulated operations and has been deferred in accordance with regulatory accounting treatment.

(b) Amounts primarily relate to ash impoundment closures and nuclear decommissioning of Crystal River Unit 3.

(c) Amounts primarily relate to AROs recorded as a result of state agency closure requirements at Duke Energy Indiana.

(d) Amounts primarily relate to increases in groundwater monitoring estimates for closure of ash impoundments and an increase for nuclear decommissioning costs at Duke Energy Carolinas' nuclear sites compared to original estimates, partially offset by a reduction for nuclear decommissioning at Crystal River Unit 3 compared to original estimates and modifications to the timing of expected cash flows for coal ash AROs.

10. PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2018								
(in millions)	**Estimated Useful Life (Years)**	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Land		**$ 2,072**	**$ 472**	**$ 868**	**$ 445**	**$ 423**	**$ 136**	**$ 116**	**$ 448**
Plant – Regulated									
Electric generation, distribution and transmission	**15-100**	**100,706**	**38,468**	**42,760**	**26,147**	**16,613**	**5,182**	**14,292**	**—**
Natural gas transmission and distribution	**12-80**	**8,808**	**—**	**—**	**—**	**—**	**2,719**	**—**	**6,089**
Other buildings and improvements	**24-90**	**1,966**	**681**	**636**	**295**	**341**	**270**	**253**	**126**
Plant – Nonregulated									
Electric generation, distribution and transmission	**5-30**	**4,410**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other buildings and improvements	**25-35**	**494**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Nuclear fuel		**3,460**	**1,898**	**1,562**	**1,562**	**—**	**—**	**—**	**—**

Equipment	**3-55**	**2,141**	**467**	**565**	**399**	**166**	**384**	**178**	**141**
Construction in process		**5,726**	**1,678**	**2,515**	**1,659**	**856**	**412**	**325**	**382**
Other	**3-40**	**4,675**	**1,077**	**1,354**	**952**	**393**	**257**	**279**	**300**
Total property, plant and equipment(a)(d)		**134,458**	**44,741**	**50,260**	**31,459**	**18,792**	**9,360**	**15,443**	**7,486**
Total accumulated depreciation – regulated(b)(c)(d)		**(41,079)**	**(15,496)**	**(16,398)**	**(11,423)**	**(4,968)**	**(2,717)**	**(4,914)**	**(1,575)**
Total accumulated depreciation – nonregulated(c)(d)		**(2,047)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Generation facilities to be retired, net		**362**	**—**	**362**	**362**	**—**	**—**	**—**	**—**
Total net property, plant and equipment		**$ 91,694**	**$ 29,245**	**$ 34,224**	**$ 20,398**	**$ 13,824**	**$ 6,643**	**$ 10,529**	**$ 5,911**

(a) Includes capitalized leases of $1,237 million, $135 million, $257 million, $137 million, $120 million, $73 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 $131 million, $14 million and $117 million, respectively, of accumulated amortization of capitalized leases.

(b) Includes $1,947 million, $1,087 million, $860 million and $860 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 $61 million, $12 million, $20 million and $10 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 $4,007 million and accumulated depreciation of consolidated VIEs of $698 million at Duke Energy.

	December 31, 2017								
(in millions)	**Estimated Useful Life (Years)**	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Land		$ 1,559	$ 467	$ 767	$ 424	$ 343	$ 134	$ 111	$ 41
Plant – Regulated									
Electric generation, distribution and transmission	8-100	93,687	35,657	39,419	24,502	14,917	4,870	13,741	—
Natural gas transmission and distribution	12-80	8,292	—	—	—	—	2,559	—	5,733
Other buildings and improvements	15-100	1,936	647	652	316	336	243	240	154
Plant – Nonregulated									
Electric generation, distribution and transmission(a)	5-30	4,273	—	—	—	—	—	—	—
Other buildings and improvements	25-35	465	—	—	—	—	—	—	—
Nuclear fuel		3,680	2,120	1,560	1,560	—	—	—	—
Equipment	3-55	2,122	402	555	416	139	348	169	266

Construction in process		6,995	2,614	3,059	1,434	1,625	350	416	231
Other	3-40	4,498	1,032	1,311	931	370	228	271	300
Total property, plant and equipment(b)(e)		127,507	42,939	47,323	29,583	17,730	8,732	14,948	6,725
Total accumulated depreciation – regulated(c)(d)(e)		(39,742)	(15,063)	(15,857)	(10,903)	(4,947)	(2,691)	(4,662)	(1,479)
Total accumulated depreciation – nonregulated(d)(e)		(1,795)	—	—	—	—	—	—	—
Generation facilities to be retired, net		421	—	421	421	—	—	—	—
Total net property, plant and equipment		$ 86,391	$ 27,876	$ 31,887	$ 19,101	$ 12,783	$ 6,041	$ 10,286	$ 5,246

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

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

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

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

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

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

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

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Duke Energy	**$ 161**	$ 128	$ 100
Duke Energy Carolinas	**35**	45	38
Progress Energy	**51**	45	31
Duke Energy Progress	**26**	21	17
Duke Energy Florida	**25**	24	14
Duke Energy Ohio	**17**	10	8
Duke Energy Indiana	**27**	9	7

	Years Ended December 31,	**Two Months Ended December 31,**	**Year Ended October 31,**

(in millions)	2018	2017	2016	2016
Piedmont	**$ 17**	$ 12	$ 2	$ 12

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 $268 million, $262 million, and $216 million for the years ended December 31, 2018, 2017 and 2016. As of December 31, 2018, renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,358 million and accumulated depreciation of $602 million. These assets are principally classified as nonregulated electric generation and transmission assets.

11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

Duke Energy

The following table presents goodwill by reportable segment for Duke Energy included on Duke Energy's Consolidated Balance Sheets at December 31, 2018, and 2017.

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
Goodwill Balance at December 31, 2017	$ 17,379	$ 1,924	$ 122	$ 19,425
Accumulated impairment charges(a)	—	—	(29)	(29)
Goodwill balance at December 31, 2017, adjusted for accumulated impairment charges	$ 17,379	$ 1,924	$ 93	$ 19,396
Goodwill Balance at December 31, 2018	**$ 17,379**	**$ 1,924**	**$ 122**	**$ 19,425**
Accumulated impairment charges(a)	**$ —**	**$ —**	**$ (122)**	**$ (122)**
Goodwill balance at December 31, 2018, adjusted for accumulated impairment charges	**$ 17,379**	**$ 1,924**	**$ —**	**$ 19,303**

(a) Duke Energy evaluated the recoverability of goodwill during 2017 and recorded impairment charges of $29 million related to the Energy Management Solutions reporting unit within the Commercial Renewables segment. The fair value of the reporting unit was determined based on the market approach. See "Goodwill Impairment Testing" below for the results of the 2018 goodwill impairment test.

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, 2018, and 2017.

Progress Energy

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

Piedmont

Piedmont's Goodwill is included in the Gas Utilities and Infrastructure segment and there are no accumulated impairment charges.

Goodwill Impairment Testing

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

In the third quarter of 2018, based on the results of the annual quantitative goodwill impairment test, management determined that the fair value of the Commercial Renewables reporting unit was below its respective carrying value, including goodwill. Determination of the Commercial Renewables reporting unit fair value was based on an income approach, which estimates the fair value based on discounted future cash flows. The fair value of the Commercial Renewables reporting unit is impacted by several factors, including forecasted tax credit utilization, the cost of capital, current and forecasted solar and wind volumes, and legislative developments. Certain assumptions used in determining the fair value of the reporting unit in the 2018 impairment test changed from those used in the 2017 annual impairment test including the cost of capital as a result of rising interest rates and the timing of tax credit utilization due to tax reform and IRS clarification on bonus depreciation in August 2018. Based on the quantitative impairment test, the estimated fair value of the Commercial Renewables reporting unit was below its carrying value by an immaterial amount but still more than the goodwill balance assigned to the reporting unit. As such, the entire remaining goodwill balance of approximately $93 million was impaired during the third quarter of 2018.

The fair value of all other reporting units for Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont exceeded their respective carrying values at the date of the annual impairment analysis.

Intangible Assets

The following tables show the carrying amount and accumulated amortization of intangible assets included in Other within Other Noncurrent Assets on the Consolidated Balance Sheets of the Duke Energy Registrants at December 31, 2018, and 2017.

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Emission allowances	$ 18	$ —	$ 5	$ 2	$ 3	$ —	$ 12	$ —
Renewable energy certificates	168	46	120	120	—	2	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	84	—	—	—	—	—	—	—
Other	6	—	—	—	—	—	—	3
Total gross carrying amounts	300	46	125	122	3	2	36	3
Accumulated amortization – natural gas, coal and power contracts	(20)	—	—	—	—	—	(20)	—
Accumulated amortization – renewable operating and development projects	(29)	—	—	—	—	—	—	—
Accumulated amortization – other	(5)	—	—	—	—	—	—	(3)
Total accumulated amortization	(54)	—	—	—	—	—	(20)	(3)
Total intangible assets, net	$ 246	$ 46	$ 125	$ 122	$ 3	$ 2	$ 16	$ —

December 31, 2017

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

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

Amortization Expense

Amortization expense amounts for natural gas, coal and power contracts, renewable operating projects and other intangible assets are immaterial for the years ended December 31, 2018, 2017 and 2016, and are expected to be immaterial for the next five years as of December 31, 2018.

12. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

EQUITY METHOD INVESTMENTS

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

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

	Years Ended December 31,					
	2018		2017		2016	
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Investments	Equity in earnings
Electric Utilities and Infrastructure	**$ 97**	**$ 6**	$ 89	$ 5	$ 93	$ 5
Gas Utilities and Infrastructure	**1,003**	**27**	763	62	566	19
Commercial Renewables	**201**	**(1)**	190	(5)	185	(82)
Other	**108**	**51**	133	57	81	43

Total	$ **1,409**	$ **83**	$ 1,175	$ 119	$ 925	$ (15)

During the years ended December 31, 2018, 2017 and 2016, Duke Energy received distributions from equity investments of $108 million, $13 million and $31 million, respectively, which are included in Other assets within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows. During the years ended December 31, 2018, and 2017, Duke Energy received distributions from equity investments of $137 million and $281 million, respectively, which are included in Return of investment capital within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

During the years ended December 31, 2018, and 2017, and the two months ended December 31, 2016, and the year ended October 31, 2016, Piedmont received distributions from equity investments of $1 million, $4 million, $1 million and $26 million, respectively, which are included in Other assets within Cash Flows from Operating Activities and $3 million, $2 million, $1 million and $18 million, respectively, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

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

Electric Utilities and Infrastructure

Duke Energy owns a 50 percent interest in DATC and in Pioneer, which build, own and operate electric transmission facilities in North America.

Gas Utilities and Infrastructure

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

		Investment Amount (in millions)	
Entity Name	**Ownership Interest**	**December 31, 2018**	**December 31, 2017**
Pipeline Investments			
Atlantic Coast Pipeline, LLC(a)	47%	$ **797**	$ 397
Sabal Trail Transmission, LLC	7.5%	**112** (d)	219
Constitution Pipeline, LLC(a)	24%	**25**	81
Cardinal Pipeline Company, LLC(b)	21.49%	**10**	11
Storage Facilities			
Pine Needle LNG Company, LLC(b)	45%	**13**	13
Hardy Storage Company, LLC(b)	50%	**46**	42
Total Investments(c)		$ **1,003**	$ 763

(a) During the year ended December 31, 2017, Piedmont transferred its share of ownership interest in ACP and Constitution to a wholly owned subsidiary of Duke Energy at book value.
(b) Piedmont owns the Cardinal, Pine Needle and Hardy Storage investments.
(c) Duke Energy includes purchase accounting adjustments related to Piedmont.
(d) Sabal Trail returned capital of $112 million during the year ended December 31, 2018.

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

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

During the fourth quarter of 2018, ACP received several adverse court rulings as described in Note 4. As a result, Duke Energy evaluated this investment for impairment and determined that fair value approximated carrying value and therefore no impairment was necessary.

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

Commercial Renewables

Duke Energy has a 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, 2018, Duke Energy recorded an OTTI of the Constitution investment of $55 million within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations. The charge represents the excess carrying value over the estimated fair value of the project, which was based on a Level 3 Fair Value measurement that was determined from the income approach using discounted cash flows. The impairment was primarily due to the recent actions taken by the courts and regulators to uphold the NYSDEC's denial of the certification and uncertainty associated with the remaining legal and regulatory challenges. For additional information on the Constitution investment, see Note 4.

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

Other

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

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)	**2018**	**2017**	**2016**
Duke Energy Carolinas			
Corporate governance and shared service expenses[(a)]	**$ 985**	$ 858	$ 831
Indemnification coverages[(b)]	**22**	23	22
JDA revenue[(c)]	**84**	49	38
JDA expense[(c)]	**207**	145	156
Intercompany natural gas purchases[(d)]	**15**	9	2
Progress Energy			
Corporate governance and shared service expenses[(a)]	**$ 906**	$ 736	$ 710
Indemnification coverages[(b)]	**34**	38	35
JDA revenue[(c)]	**207**	145	156
JDA expense[(c)]	**84**	49	38
Intercompany natural gas purchases[(d)]	**78**	77	19
Duke Energy Progress			
Corporate governance and shared service expenses[(a)]	**$ 577**	$ 438	$ 397
Indemnification coverages[(b)]	**13**	15	14
JDA revenue[(c)]	**207**	145	156
JDA expense[(c)]	**84**	49	38

Intercompany natural gas purchases[d]		**78**		77		19
Duke Energy Florida						
Corporate governance and shared service expenses[a]	**$**	**329**	$	298	$	313
Indemnification coverages[b]		**21**		23		21
Duke Energy Ohio						
Corporate governance and shared service expenses[a]	**$**	**374**	$	363	$	356
Indemnification coverages[b]		**5**		5		5
Duke Energy Indiana						
Corporate governance and shared service expenses[a]	**$**	**405**	$	370	$	366
Indemnification coverages[b]		**7**		8		8
Piedmont						
Corporate governance and shared service expenses[a]	**$**	**170**	$	50		
Indemnification coverages[b]		**2**		2		
Intercompany natural gas sales[d]		**93**		86		
Natural gas storage and transportation costs[e]		**25**		25		

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

(f) 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.

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

(h) Piedmont provides long-term natural gas delivery service to certain Duke Energy Carolinas and Duke Energy Progress natural gas-fired generation facilities. Piedmont records the sales in Operating Revenues, and Duke Energy Carolinas and Duke Energy Progress record the related purchases as a component of Fuel used in electric generation and purchased power on their respective Consolidated Statements of Operations and Comprehensive Income. These intercompany revenues and expenses are eliminated in consolidation. For the two months ended December 31, 2016, and for sales made subsequent to the acquisition for the year ended October 31, 2016, Piedmont recorded $14 million and $7 million, respectively, of natural gas sales with Duke Energy. For sales made prior to the acquisition for the year ended October 31, 2016, Piedmont recorded $74 million of natural gas sales with Duke Energy.

(i) Piedmont has related party transactions as a customer of its equity method investments in Pine Needle, Hardy Storage, and Cardinal natural gas storage and transportation facilities. These expenses are included in Cost of natural gas on Piedmont's Consolidated Statements of Operations and Comprehensive Income. For the two months ended December 31, 2016, and for the year ended October 31, 2016, Piedmont recorded $6 million and $29 million, respectively, of natural gas storage and transportation costs.

In addition to the amounts presented above, the Subsidiary Registrants have other affiliate transactions, including rental of office space, participation in a money pool arrangement, other operational transactions and their proportionate share of certain charged expenses. See Note 6 for more information regarding money pool. These transactions of the Subsidiary Registrants are incurred in the ordinary course of business and are eliminated in consolidation.

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.

Intercompany Income Taxes

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

(in millions)	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
December 31, 2018							
Intercompany income tax receivable	**$ 52**	**$ 47**	**$ 29**	**$ —**	**$ —**	**$ 8**	**$ —**
Intercompany income tax payable	**—**	**—**	**—**	**16**	**3**	**—**	**45**
December 31, 2017							
Intercompany income tax receivable	$ —	$ 168	$ —	$ 44	$ 22	$ —	$ 7
Intercompany income tax payable	44	—	21	—	—	35	—

14. DERIVATIVES AND HEDGING

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

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

INTEREST RATE RISK

The Duke Energy Registrants are exposed to changes in interest rates as a result of their issuance or anticipated issuance of variable-rate and fixed-rate debt and commercial paper. Interest rate risk is managed by limiting variable-rate exposures to a percentage of total debt and by monitoring changes in interest rates. To manage risk associated with changes in interest rates, the Duke Energy Registrants may enter into interest rate swaps, U.S. Treasury lock agreements and other financial contracts. In anticipation of certain fixed-rate debt issuances, a series of forward-starting interest rate swaps or Treasury locks 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. Gains and losses reclassified out of AOCI for the years ended December 31, 2018, 2017 and 2016 were not material. 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 primarily include contracts not designated as a hedge because they are accounted for under regulatory accounting or 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 on the Duke Energy Registrant's Consolidated Statements of Operations and Comprehensive Income.

In August 2016, Duke Energy unwound $1.4 billion of forward-starting interest rate swaps associated with the Piedmont acquisition financing. 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, 2018					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio
Cash flow hedges	$ 923	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	1,721	300	1,200	650	550	27
Total notional amount[(a)]	$ 2,644	$ 300	$ 1,200	$ 650	$ 550	$ 27

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

(a) Duke Energy includes amounts related to consolidated VIEs of $422 million in cash flow hedges and $194 million in undesignated contracts as of December 31, 2018, and $660 million in cash flow hedges as of December 31, 2017.

COMMODITY PRICE RISK

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

Volumes

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

	December 31, 2018							
	Duke Energy	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Electricity (gigawatt-hours)	**15,286**	**—**	**—**	**—**	**—**	**1,786**	**13,500**	**—**
Natural gas (millions of dekatherms)	**739**	**121**	**169**	**166**	**3**	**—**	**1**	**448**

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

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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 35	$ 2	$ 2	$ 2	$ —	$ 6	$ 23	$ 3
Noncurrent	4	1	2	2	—	—	—	—
Total Derivative Assets – Commodity Contracts	$ 39	$ 3	$ 4	$ 4	$ —	$ 6	$ 23	$ 3
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	3	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	2	—	—	—	—	—	—	—
Noncurrent	12	—	—	—	—	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 18	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Total Derivative Assets	**$ 57**	**$ 3**	**$ 4**	**$ 4**	**$ —**	**$ 6**	**$ 23**	**$ 3**

Derivative Liabilities	**December 31, 2018**							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	**$ 33**	**$ 14**	**$ 10**	**$ 5**	**$ 6**	**$ —**	**$ —**	**$ 8**
Noncurrent	**158**	**10**	**15**	**6**	**—**	**—**	**—**	**133**
Total Derivative Liabilities – Commodity Contracts	**$ 191**	**$ 24**	**$ 25**	**$ 11**	**$ 6**	**$ —**	**$ —**	**$ 141**
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	**$ 12**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Noncurrent	**6**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Not Designated as Hedging Instruments								
Current	**23**	**9**	**13**	**11**	**2**	**1**	**—**	**—**
Noncurrent	**10**	**—**	**6**	**5**	**1**	**4**	**—**	**—**
Total Derivative Liabilities – Interest Rate Contracts	**$ 51**	**$ 9**	**$ 19**	**$ 16**	**$ 3**	**$ 5**	**$ —**	**$ —**
Total Derivative Liabilities	**$ 242**	**$ 33**	**$ 44**	**$ 27**	**$ 9**	**$ 5**	**$ —**	**$ 141**

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

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

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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	**$ 38**	**$ 2**	**$ 2**	**$ 2**	**$ —**	**$ 6**	**$ 23**	**$ 3**
Gross amounts offset	**(3)**	**(2)**	**(2)**	**(2)**	**—**	**—**	**—**	**—**
Net amounts presented in Current Assets: Other	**$ 35**	**$ —**	**$ —**	**$ —**	**$ —**	**$ 6**	**$ 23**	**$ 3**
Noncurrent								
Gross amounts recognized	**$ 19**	**$ 1**	**$ 2**	**$ 2**	**$ —**	**$ —**	**$ —**	**$ —**
Gross amounts offset	**(3)**	**(1)**	**(2)**	**(2)**	**—**	**—**	**—**	**—**
Net amounts presented in Other								

Noncurrent Assets: Other	$ 16	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Derivative Liabilities — December 31, 2018

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 68	$ 23	$ 23	$ 16	$ 8	$ 1	$ —	$ 8
Gross amounts offset	(4)	(2)	(2)	(2)	—	—	—	—
Net amounts presented in Current Liabilities: Other	$ 64	$ 21	$ 21	$ 14	$ 8	$ 1	$ —	$ 8
Noncurrent								
Gross amounts recognized	$ 174	$ 10	$ 21	$ 11	$ 1	$ 4	$ —	$ 133
Gross amounts offset	(3)	(1)	(2)	(2)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 171	$ 9	$ 19	$ 9	$ 1	$ 4	$ —	$ 133

Derivative Assets — December 31, 2017

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

Derivative Liabilities — December 31, 2017

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								

Gross amounts recognized	$ 66	$ 31	$ 19	$ 8	$ 10	$ 1	$ —	$ 11
Gross amounts offset	(3)	(2)	(2)	(2)	—	—	—	—
Net amounts presented in Current Liabilities: Other	$ 63	$ 29	$ 17	$ 6	$ 10	$ 1	$ —	$ 11
Noncurrent								
Gross amounts recognized	$ 164	$ 4	$ 17	$ 10	$ 2	$ 4	$ —	$ 131
Gross amounts offset	(1)	—	(1)	(1)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 163	$ 4	$ 16	$ 9	$ 2	$ 4	$ —	$ 131

OBJECTIVE CREDIT CONTINGENT FEATURES

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

	December 31, 2018				
(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	**$ 44**	**$ 19**	**$ 25**	**$ 25**	**$ —**
Fair value of collateral already posted	**—**	**—**	**—**	**—**	**—**
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	**44**	**19**	**25**	**25**	**—**

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

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

15. INVESTMENTS IN DEBT AND EQUITY SECURITIES

Duke Energy's investments in debt and equity securities are primarily comprised of investments held in (i) the NDTF at Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, (ii) the grantor trusts at Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana related to OPEB plans and (iii) Bison. The Duke Energy Registrants classify investments in debt securities as AFS and investments in equity securities as FV-NI. For investments in debt securities classified as AFS, the unrealized gains and losses are included in other comprehensive income until realized, at which time, they are reported though net income. For investments in equity securities classified as FV-NI, both realized and unrealized gains and losses are reported through net income. Substantially all of Duke Energy's investments in debt and equity securities qualify for regulatory accounting, and accordingly, all associated realized and unrealized gains and losses on these investments are deferred as a regulatory asset or liability.

Duke Energy classifies the majority of investments in debt and equity securities as long term, unless otherwise noted.

Investment Trusts

The investments within the NDTF and the 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 securities within the Investment Trusts are considered OTTIs and are recognized immediately and deferred to regulatory accounts where appropriate.

Other AFS Securities

Unrealized gains and losses on all other AFS securities are included in other comprehensive income until realized, unless it is determined the carrying value of an investment is other-than-temporarily impaired. 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. If an OTTI exists, the unrealized credit loss is included in earnings. There were no material credit losses as of December 31, 2018, and 2017.

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

DUKE ENERGY

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2018			December 31, 2017		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 88**	$ —	$ —	$ 115
Equity securities	**2,402**	**95**	**4,475**	2,805	27	4,914
Corporate debt securities	**4**	**13**	**566**	17	2	570
Municipal bonds	**1**	**4**	**353**	4	3	344
U.S. government bonds	**14**	**12**	**1,076**	11	7	1,027
Other debt securities	**—**	**2**	**148**	—	1	118
Total NDTF Investments	**$ 2,421**	**$ 126**	**$ 6,706**	$ 2,837	$ 40	$ 7,088

Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 22**	$ —	$ —	$ 15
Equity securities	**36**	**1**	**99**	59	—	123
Corporate debt securities	**—**	**2**	**60**	1	—	57
Municipal bonds	**—**	**1**	**85**	2	1	83
U.S. government bonds	**1**	**—**	**45**	—	—	41
Other debt securities	**—**	**1**	**58**	—	1	44
Total Other Investments	**$ 37**	**$ 5**	**$ 369**	$ 62	$ 2	$ 363
Total Investments	**$ 2,458**	**$ 131**	**$ 7,075**	$ 2,899	$ 42	$ 7,451

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2018**
Due in one year or less	**$ 98**
Due after one through five years	**501**
Due after five through 10 years	**570**
Due after 10 years	**1,222**
Total	**$ 2,391**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

	Year Ended December 31,
(in millions)	**2018**
FV-NI:	
Realized gains	**$ 168**
Realized losses	**126**
AFS:	
Realized gains	**22**
Realized losses	**51**

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

DUKE ENERGY CAROLINAS

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2018			**December 31, 2017**		
	Gross Unrealized	**Gross Unrealized**		**Gross Unrealized**	**Gross Unrealized**	

(in millions)		Holding Gains		Holding Losses		Estimated Fair Value		Holding Gains		Holding Losses		Estimated Fair Value
NDTF												
Cash and cash equivalents	**$**	**—**	**$**	**—**	**$**	**29**	$	—	$	—	$	32
Equity securities		**1,309**		**54**		**2,484**		1,531		12		2,692
Corporate debt securities		**2**		**9**		**341**		9		2		359
Municipal bonds		**—**		**1**		**81**		—		1		60
U.S. government bonds		**5**		**8**		**475**		3		4		503
Other debt securities		**—**		**2**		**143**		—		1		112
Total NDTF Investments	**$**	**1,316**	**$**	**74**	**$**	**3,553**	$	1,543	$	20	$	3,758

The table below summarizes the maturity date for debt securities.

(in millions)		December 31, 2018
Due in one year or less	**$**	**6**
Due after one through five years		**142**
Due after five through 10 years		**303**
Due after 10 years		**589**
Total	**$**	**1,040**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

		Year Ended December 31,
(in millions)		**2018**
FV-NI:		
Realized gains	**$**	**89**
Realized losses		**73**
AFS:		
Realized gains		**19**
Realized losses		**35**

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

PROGRESS ENERGY

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2018			December 31, 2017		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 59**	$ —	$ —	$ 83
Equity securities	**1,093**	**41**	**1,991**	1,274	15	2,222
Corporate debt securities	**2**	**4**	**225**	8	—	211
Municipal bonds	**1**	**3**	**272**	4	2	284
U.S. government bonds	**9**	**4**	**601**	8	3	524
Other debt securities	**—**	**—**	**5**	—	—	6
Total NDTF Investments	**$ 1,105**	**$ 52**	**$ 3,153**	$ 1,294	$ 20	$ 3,330
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 17**	$ —	$ —	$ 12
Municipal bonds	**—**	**—**	**47**	2	—	47
Total Other Investments	**$ —**	**$ —**	**$ 64**	$ 2	$ —	$ 59
Total Investments	**$ 1,105**	**$ 52**	**$ 3,217**	$ 1,296	$ 20	$ 3,389

The table below summarizes the maturity date for debt securities.

(in millions)		December 31, 2018
Due in one year or less	$	87
Due after one through five years		306
Due after five through 10 years		216
Due after 10 years		541
Total	$	1,150

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

		Year Ended December 31,
(in millions)		2018
FV-NI:		
Realized gains	$	79
Realized losses		53
AFS:		
Realized gains		3
Realized losses		15

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

DUKE ENERGY PROGRESS

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2018			December 31, 2017		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value

NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 46**	$ —	$ —	$ 50
Equity securities	**833**	**30**	**1,588**	980	12	1,795
Corporate debt securities	**2**	**3**	**171**	6	—	149
Municipal bonds	**1**	**3**	**271**	4	2	283
U.S. government bonds	**6**	**3**	**415**	5	2	310
Other debt securities	**—**	**—**	**3**	—	—	4
Total NDTF Investments	**$ 842**	**$ 39**	**$ 2,494**	$ 995	$ 16	$ 2,591
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 6**	$ —	$ —	$ 1
Total Other Investments	**$ —**	**$ —**	**$ 6**	$ —	$ —	$ 1
Total Investments	**$ 842**	**$ 39**	**$ 2,500**	$ 995	$ 16	$ 2,592

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2018**
Due in one year or less	**$ 49**
Due after one through five years	**231**
Due after five through 10 years	**161**
Due after 10 years	**419**
Total	**$ 860**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

	Year Ended December 31,
(in millions)	**2018**
FV-NI:	
Realized gains	**$ 68**
Realized losses	**48**
AFS:	
Realized gains	**$ 2**
Realized losses	**10**

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

DUKE ENERGY FLORIDA

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2018			December 31, 2017		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 13	$ —	$ —	$ 33
Equity securities	260	11	403	294	3	427
Corporate debt securities	—	1	54	2	—	62
Municipal bonds	—	—	1	—	—	1
U.S. government bonds	3	1	186	3	1	214
Other debt securities	—	—	2	—	—	2
Total NDTF Investments[(a)]	$ 263	$ 13	$ 659	$ 299	$ 4	$ 739
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 1	$ —	$ —	$ 1
Municipal bonds	—	—	47	2	—	47
Total Other Investments	$ —	$ —	$ 48	$ 2	$ —	$ 48
Total Investments	$ 263	$ 13	$ 707	$ 301	$ 4	$ 787

(a) During the year ended December 31, 2018, Duke Energy Florida continued to receive reimbursements from the NDTF for costs related to ongoing decommissioning activity of the Crystal River Unit 3 nuclear plant.

The table below summarizes the maturity date for debt securities.

(in millions)		**December 31, 2018**
Due in one year or less	**$**	**38**
Due after one through five years		**75**
Due after five through 10 years		**55**
Due after 10 years		**122**
Total	**$**	**290**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were as follows.

		Year Ended December 31,
(in millions)		**2018**
FV-NI:		
Realized gains	**$**	**11**
Realized losses		**5**
AFS:		
Realized gains		**1**
Realized losses		**5**

	Years Ended December 31,			
(in millions)		2017		2016
Realized gains	$	11	$	13
Realized losses		8		9

DUKE ENERGY INDIANA

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are measured at FV-NI and debt investments are classified as AFS.

	December 31, 2018						**December 31, 2017**					
(in millions)		**Gross Unrealized Holding Gains**		**Gross Unrealized Holding Losses**		**Estimated Fair Value**		**Gross Unrealized Holding Gains**		**Gross Unrealized Holding Losses**		**Estimated Fair Value**
Investments												
Equity securities	**$**	**29**	**$**	**—**	**$**	**67**	$	49	$	—	$	97
Corporate debt securities		**—**		**—**		**8**		—		—		3
Municipal bonds		**—**		**1**		**33**		—		1		28
Total Investments	**$**	**29**	**$**	**1**	**$**	**108**	$	49	$	1	$	128

The table below summarizes the maturity date for debt securities.

(in millions)		**December 31, 2018**
Due in one year or less	**$**	**3**

Due after one through five years		**20**
Due after five through 10 years		**4**
Due after 10 years		**14**
Total	**$**	**41**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2018, and from sales of AFS securities for the years ended December 31, 2017, and 2016, were insignificant.

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 as defined by GAAP. Certain investments are not categorized within the fair value hierarchy. These investments are measured at fair value using the NAV per share practical expedient. The NAV is derived based on the investment cost, less any impairment, plus or minus changes resulting from observable price changes for an identical or similar investment of the same issuer.

Fair value accounting guidance permits entities to elect to measure certain financial instruments that are not required to be accounted for at fair value, such as equity method investments or the company’s own debt, at fair value. The Duke Energy Registrants have not elected to record any of these items at fair value.

Transfers between levels represent assets or liabilities that were previously (i) categorized at a higher level for which the inputs to the estimate became less observable or (ii) classified at a lower level for which the inputs became more observable during the period. The Duke Energy Registrant’s policy is to recognize transfers between levels of the fair value hierarchy at the end of the period. There were no transfers between levels during the years ended December 31, 2018, 2017 and 2016. In addition, for Piedmont, there were no transfers between levels during the two months ended December 31, 2016, and the year ended October 31, 2016.

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 NYSE and the Nasdaq Stock Market. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. There was no after-hours market activity that was required to be reflected in the reported fair value measurements.

Investments in debt securities

Most investments in debt securities are valued using Level 2 measurements because the valuations use interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. If the market for a particular fixed-income security is relatively inactive or illiquid, the measurement is Level 3.

Commodity derivatives

Commodity derivatives with clearinghouses are classified as Level 1. Other commodity derivatives, including Piedmont's natural gas supply contracts, are primarily valued using internally developed discounted cash flow models that incorporate forward price, adjustments for liquidity (bid-ask spread) and credit or non-performance risk (after reflecting credit enhancements such as collateral), and are discounted to present value. Pricing inputs are derived from published exchange transaction prices and other observable data sources. In the absence of an active market, the last available price may be used. If forward price curves are not observable for the full term of the contract and the unobservable period had more than an insignificant impact on the valuation, the commodity derivative is classified as Level 3. In isolation, increases (decreases) in natural gas forward prices result in favorable (unfavorable) fair value adjustments for natural gas purchase contracts; and increases (decreases) in electricity forward prices result in unfavorable (favorable) fair value adjustments for electricity sales contracts. Duke Energy regularly evaluates and validates pricing inputs used to estimate the fair value of natural gas commodity contracts by a market participant price verification procedure. This procedure provides a comparison of internal forward commodity curves to market participant generated curves.

Interest rate derivatives

Most over-the-counter interest rate contract derivatives are valued using financial models that utilize observable inputs for similar instruments and are classified as Level 2. Inputs include forward interest rate curves, notional amounts, interest rates and credit quality of the counterparties.

Other fair value considerations

See Note 11 for a discussion of the valuation of goodwill and intangible assets.

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 tables below for all Duke Energy Registrants exclude cash collateral, which is disclosed in Note 14. See Note 15 for additional information related to investments by major security type for the Duke Energy Registrants.

	December 31, 2018				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	**$ 4,475**	**$ 4,410**	**$ —**	**$ —**	**$ 65**
NDTF debt securities	**2,231**	**576**	**1,655**	**—**	**—**
Other equity securities	**99**	**99**	**—**	**—**	**—**
Other debt securities	**270**	**67**	**203**	**—**	**—**
Derivative assets	**57**	**4**	**25**	**28**	**—**
Total assets	**7,132**	**5,156**	**1,883**	**28**	**65**
Derivative liabilities	**(242)**	**(11)**	**(90)**	**(141)**	**—**
Net assets (liabilities)	**$ 6,890**	**$ 5,145**	**$ 1,793**	**$ (113)**	**$ 65**

	December 31, 2017				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	$ 4,914	$ 4,840	$ —	$ —	$ 74
NDTF debt securities	2,174	635	1,539	—	—
Other equity securities	123	123	—	—	—
Other debt securities	241	57	184	—	—
Derivative assets	51	3	20	28	—

Total assets	7,503	5,658	1,743	28	74
Derivative liabilities	(230)	(2)	(86)	(142)	—
Net assets (liabilities)	$ 7,273	$ 5,656	$ 1,657	$ (114)	$ 74

The following tables provide reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements. Amounts included in earnings for derivatives are primarily included in Cost of natural gas on the Duke Energy Registrants' Consolidated Statements of Operations and Comprehensive Income. Amounts included in changes of net assets on the Duke Energy Registrants' Consolidated Balance Sheets are included in regulatory assets or liabilities. All derivative assets and liabilities are presented on a net basis.

	December 31, 2018	**December 31, 2017**		
(in millions)	**Derivatives (net)**	**Investments**	**Derivatives (net)**	**Total**
Balance at beginning of period	**$ (114)**	$ 5	$ (166)	$ (161)
Total pretax realized or unrealized gains included in comprehensive income	**—**	1	—	1
Purchases, sales, issuances and settlements:				
Purchases	**57**	—	55	55
Sales	**—**	(6)	—	(6)
Settlements	**(57)**	—	(47)	(47)
Total gains included on the Consolidated Balance Sheet	**1**	—	44	44
Balance at end of period	**$ (113)**	$ —	$ (114)	$ (114)

DUKE ENERGY CAROLINAS

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Not Categorized**
NDTF equity securities	**$ 2,484**	**$ 2,419**	**$ —**	**$ 65**
NDTF debt securities	**1,069**	**149**	**920**	**—**

Derivative assets	**3**	**—**	**3**	**—**
Total assets	**3,556**	**2,568**	**923**	**65**
Derivative liabilities	**(33)**	**—**	**(33)**	**—**
Net assets	**$ 3,523**	**$ 2,568**	**$ 890**	**$ 65**

	December 31, 2017			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Not Categorized**
NDTF equity securities	$ 2,692	$ 2,618	$ —	$ 74
NDTF debt securities	1,066	204	862	—
Derivative assets	2	—	2	—
Total assets	3,760	2,822	864	74
Derivative liabilities	(35)	(1)	(34)	—
Net assets	$ 3,725	$ 2,821	$ 830	$ 74

The following table provides reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Investments
	Year Ended December 31,
(in millions)	**2017**
Balance at beginning of period	$ 3
Total pretax realized or unrealized gains included in comprehensive income	1
Purchases, sales, issuances and settlements:	
Sales	(4)
Balance at end of period	$ —

PROGRESS ENERGY

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018			**December 31, 2017**		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 1,991**	**$ 1,991**	**$ —**	$ 2,222	$ 2,222	$ —
NDTF debt securities	**1,162**	**427**	**735**	1,108	431	677
Other debt securities	**64**	**17**	**47**	59	12	47
Derivative assets	**4**	**—**	**4**	3	1	2
Total assets	**3,221**	**2,435**	**786**	3,392	2,666	726
Derivative liabilities	**(44)**	**—**	**(44)**	(36)	(1)	(35)
Net assets	**$ 3,177**	**$ 2,435**	**$ 742**	$ 3,356	$ 2,665	$ 691

DUKE ENERGY PROGRESS

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 1,588	$ 1,588	$ —	$ 1,795	$ 1,795	$ —
NDTF debt securities	906	294	612	796	243	553
Other debt securities	6	6	—	1	1	—
Derivative assets	4	—	4	2	1	1
Total assets	2,504	1,888	616	2,594	2,040	554
Derivative liabilities	(27)	—	(27)	(18)	(1)	(17)
Net assets	$ 2,477	$ 1,888	$ 589	$ 2,576	$ 2,039	$ 537

DUKE ENERGY FLORIDA

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 403	$ 403	$ —	$ 427	$ 427	$ —
NDTF debt securities	256	133	123	312	188	124
Other debt securities	48	1	47	48	1	47
Derivative assets	—	—	—	1	—	1
Total assets	707	537	170	788	616	172
Derivative liabilities	(9)	—	(9)	(12)	—	(12)
Net assets	$ 698	$ 537	$ 161	$ 776	$ 616	$ 160

DUKE ENERGY OHIO

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018			December 31, 2017		
(in millions)	Total Fair Value	Level 2	Level 3	Total Fair Value	Level 2	Level 3
Derivative assets	$ 6	$ —	$ 6	$ 1	$ —	$ 1
Derivative liabilities	(5)	(5)	—	(5)	(5)	—
Net assets (liabilities)	$ 1	$ (5)	$ 6	$ (4)	$ (5)	$ 1

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)	**2018**	**2017**
Balance at beginning of period	**$ 1**	$ 5
Purchases, sales, issuances and settlements:		
Purchases	**7**	3
Settlements	**(4)**	(4)
Total gains included on the Consolidated Balance Sheet	**2**	(3)
Balance at end of period	**$ 6**	$ 1

DUKE ENERGY INDIANA

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018				December 31, 2017			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**
Other equity securities	**$ 67**	**$ 67**	**$ —**	**$ —**	$ 97	$ 97	$ —	$ —
Other debt securities	**41**	**—**	**41**	**—**	31	—	31	—
Derivative assets	**23**	**1**	**—**	**22**	27	—	—	27
Total assets	**$ 131**	**$ 68**	**$ 41**	**$ 22**	$ 155	$ 97	$ 31	$ 27

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)	**2018**	**2017**
Balance at beginning of period	**$ 27**	$ 16
Purchases, sales, issuances and settlements:		
Purchases	**50**	52
Settlements	**(53)**	(43)
Total (losses) gains included on the Consolidated Balance Sheet	**(2)**	2
Balance at end of period	**$ 22**	$ 27

PIEDMONT

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2018			December 31, 2017		
(in millions)	**Total Fair Value**	**Level 1**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 3**
Other debt securities	**$ —**	**$ —**	**$ —**	$ 1	$ 1	$ —
Derivative assets	**3**	**3**	**—**	2	2	—
Total assets	**3**	**3**	**—**	3	3	—
Derivative liabilities	**(141)**	**—**	**(141)**	(142)	—	(142)
Net (liabilities) assets	**$ (138)**	**$ 3**	**$ (141)**	$ (139)	$ 3	$ (142)

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)	**2018**	**2017**
Balance at beginning of period	**$ (142)**	$ (187)
Total gains and settlements	**1**	45
Balance at end of period	**$ (141)**	$ (142)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

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

	December 31, 2018			
Investment Type	**Fair Value (in millions)**	**Valuation Technique**	**Unobservable Input**	**Range**
Duke Energy Ohio				
FTRs	**$ 6**	RTO auction pricing	FTR price – per MWh	**$ 1.19 – $ 4.59**
Duke Energy Indiana				
FTRs	**22**	RTO auction pricing	FTR price – per MWh	**(2.07) – 8.27**
Piedmont				
Natural gas contracts	**(141)**	Discounted cash flow	Forward natural gas curves — price per MMBtu	**1.87 – 2.95**
Duke Energy				
Total Level 3 derivatives	**$ (113)**			

	December 31, 2017			
Investment Type	**Fair Value (in millions)**	**Valuation Technique**	**Unobservable Input**	**Range**
Duke Energy Ohio				
FTRs	$ 1	RTO auction pricing	FTR price – per MWh	$ 0.07 – $ 1.41
Duke Energy Indiana				
FTRs	27	RTO auction pricing	FTR price – per MWh	(0.77) – 7.44
Piedmont				
Natural gas contracts	(142)	Discounted cash flow	Forward natural gas curves — price per MMBtu	2.10 – 2.88
Duke Energy				
Total Level 3 derivatives	$ (114)			

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, 2018		December 31, 2017	
(in millions)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Duke Energy[(a)]	**$ 54,529**	**$ 54,534**	$ 52,279	$ 55,331
Duke Energy Carolinas	**10,939**	**11,471**	10,103	11,372
Progress Energy	**18,911**	**19,885**	17,837	20,000
Duke Energy Progress	**8,204**	**8,300**	7,357	7,992
Duke Energy Florida	**7,321**	**7,742**	7,095	7,953
Duke Energy Ohio	**2,165**	**2,239**	2,067	2,249
Duke Energy Indiana	**3,782**	**4,158**	3,783	4,464
Piedmont	**2,138**	**2,180**	2,037	2,209

(a) Book value of long-term debt includes $1.6 billion as of December 31, 2018, and $1.7 billion as of December 31, 2017, of unamortized debt discount and premium, net in purchase accounting adjustments related to the mergers with Progress Energy and Piedmont that are excluded from fair value of long-term debt.

At both December 31, 2018, and December 31, 2017, fair value of cash and cash equivalents, accounts and notes receivable, accounts payable, notes payable and commercial paper, and nonrecourse notes payable of VIEs are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

17. VARIABLE INTEREST ENTITIES

A VIE is an entity that is evaluated for consolidation using more than a simple analysis of voting control. The analysis to determine whether an entity is a VIE considers contracts with an entity, credit support for an entity, the adequacy of the equity investment of an entity and the relationship of voting power to the amount of equity invested in an entity. This analysis is performed either upon the creation of a legal entity or upon the occurrence of an event requiring reevaluation, such as a significant change in an entity's assets or activities. A qualitative analysis of control determines the party that consolidates a VIE. This assessment is based on (i) what party has the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) what party has rights to receive benefits or is obligated to absorb losses that could potentially be significant to the VIE. The analysis of the party that consolidates a VIE is a continual reassessment.

CONSOLIDATED VIEs

The obligations of these VIEs discussed in the following paragraphs are nonrecourse to the Duke Energy Registrants. The registrants have no requirement to provide liquidity to, purchase assets of or guarantee performance of these VIEs unless noted in the following paragraphs.

No financial support was provided to any of the consolidated VIEs during the years ended December 31, 2018, 2017 and 2016, or is expected to be provided in the future, that was not previously contractually required.

Receivables Financing – DERF/DEPR/DEFR

DERF, DEPR and 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 are considered the primary beneficiaries and 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 approximately 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 is considered the primary beneficiary and consolidates CRC as it makes these decisions. Neither Duke Energy Ohio nor Duke Energy Indiana consolidate CRC.

Receivables Financing – Credit Facilities

The following table outlines amounts and expiration dates of the credit facilities described above.

	Duke Energy			
		Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
	CRC	DERF	DEPR	DEFR

Expiration date	December 2020	December 2020	February 2021	April 2021
Credit facility amount (in millions)	$ 325	$ 450	$ 300	$ 225
Amounts borrowed at December 31, 2018	325	450	300	225
Amounts borrowed at December 31, 2017	325	450	300	225
Restricted Receivables at December 31, 2018	564	699	547	357
Restricted Receivables at December 31, 2017	545	640	459	317

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 2016, DEFPF issued 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, 2018	December 31, 2017
Receivables of VIEs	**$ 5**	$ 4
Regulatory Assets: Current	**52**	51
Current Assets: Other	**39**	40
Other Noncurrent Assets: Regulatory assets	**1,041**	1,091
Current Liabilities: Other	**10**	10
Current maturities of long-term debt	**53**	53
Long-Term Debt	**1,111**	1,164

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. Additionally, Duke Energy has VIEs associated with tax equity arrangements entered into with third–party investors in order to finance the cost of solar energy systems eligible for tax credits. The activities that most significantly impacted the economic performance of these renewable energy facilities were decisions associated with siting, negotiating PPAs and EPC agreements, and decisions associated with ongoing operations and maintenance-related activities. Duke Energy is considered the primary beneficiary and 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, 2018	December 31, 2017
Current Assets: Other	**$ 123**	$ 174
Property, plant and equipment, cost	**4,007**	3,923
Accumulated depreciation and amortization	**(698)**	(591)

Other Noncurrent Assets: Other	**261**	50
Current maturities of long-term debt	**174**	170
Long-Term Debt	**1,587**	1,700
Other Noncurrent Liabilities: Deferred income taxes	**—**	(148)
Other Noncurrent Liabilities: Asset Retirement Obligations	**106**	83
Other Noncurrent Liabilities: Other	**212**	241

NON-CONSOLIDATED VIEs

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

	December 31, 2018					
	Duke Energy				**Duke Energy**	**Duke Energy**
(in millions)	**Pipeline Investments**	**Commercial Renewables**	**Other VIEs**	**Total**	**Ohio**	**Indiana**
Receivables from affiliated companies	**$ —**	**$ —**	**$ —**	**$ —**	**$ 93**	**$ 118**
Investments in equity method unconsolidated affiliates	**822**	**190**	**48**	**1,060**	**—**	**—**
Total assets	**$ 822**	**$ 190**	**$ 48**	**$ 1,060**	**$ 93**	**$ 118**
Taxes accrued	**(1)**	**—**	**—**	**(1)**	**—**	**—**
Other current liabilities	**—**	**—**	**4**	**4**	**—**	**—**
Deferred income taxes	**21**	**—**	**—**	**21**	**—**	**—**
Other noncurrent liabilities	**—**	**—**	**12**	**12**	**—**	**—**
Total liabilities	**$ 20**	**$ —**	**$ 16**	**$ 36**	**$ —**	**$ —**
Net assets	**$ 802**	**$ 190**	**$ 32**	**$ 1,024**	**$ 93**	**$ 118**

	December 31, 2017					
	Duke Energy				**Duke Energy**	**Duke Energy**
(in millions)	**Pipeline Investments**	**Commercial Renewables**	**Other VIEs**	**Total**	**Ohio**	**Indiana**
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 87	$ 106

Investments in equity method unconsolidated affiliates	697	180	42	919	—	—
Other noncurrent assets	17	—	—	17	—	—
Total assets	$ 714	$ 180	$ 42	$ 936	$ 87	$ 106
Taxes accrued	(29)	—	—	(29)	—	—
Other current liabilities	—	—	4	4	—	—
Deferred income taxes	42	—	—	42	—	—
Other noncurrent liabilities	—	—	12	12	—	—
Total liabilities	$ 13	$ —	$ 16	$ 29	$ —	$ —
Net assets	$ 701	$ 180	$ 26	$ 907	$ 87	$ 106

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, including Duke Energy's guarantee agreement to support its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is $677 million as of December 31, 2018. 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 these joint ventures.

		Investment Amount (in millions)	
Entity Name	**Ownership Interest**	**December 31, 2018**	**December 31, 2017**
ACP	47%	**$ 797**	$ 397
Sabal Trail[(a)]	7.5%	**—**	219
Constitution[(b)]	24%	**25**	81
Total		**$ 822**	$ 697

(a) At December 31, 2017, Sabal Trail was considered a VIE due to having insufficient equity to finance their own activities without subordinated financial support. However, Sabal Trail is now a fully operational, well capitalized entity. As a result, Sabal Trail has sufficient equity to finance its own activities, and therefore, is no longer considered a VIE. Duke Energy's investment in Sabal Trail was $112 million at December 31, 2018.

(b) During the year ended December 31, 2018, Duke Energy recorded an OTTI of $55 million related to Constitution within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Income. See Note 4 for additional information.

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.

Pioneer

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 its activities without subordinated financial support. The activities that most significantly impact OVEC's economic performance include fuel strategy and supply activities and decisions associated with ongoing operations and maintenance-related activities. Duke Energy Ohio does not have the unilateral power to direct these activities, and therefore, does not consolidate OVEC.

As a counterparty to an ICPA, Duke Energy Ohio has a contractual arrangement to receive entitlements to capacity and energy 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. On March 31, 2018, FES, a subsidiary of FirstEnergy and an ICPA counterparty with a power participation ratio of 4.85 percent, filed for Chapter 11 bankruptcy, which could increase costs allocated to the counterparties. On July 31, 2018, the bankruptcy court rejected the FES ICPA, which means OVEC is an unsecured creditor in the FES bankruptcy proceeding. Duke Energy Ohio cannot predict the impact of the bankruptcy filing on its OVEC interests. In addition, certain proposed environmental rulemaking could result in future increased OVEC cost allocations. See Note 4 for additional information.

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	
	2018	**2017**	**2018**	**2017**
Anticipated credit loss ratio	**0.5%**	0.5%	**0.3%**	0.3%
Discount rate	**3.0%**	2.1%	**3.0%**	2.1%
Receivable turnover rate	**13.5%**	13.5%	**11.0%**	10.7%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio	Duke Energy Indiana

(in millions)	2018	2017	2018	2017
Receivables sold	**$ 269**	$ 273	**$ 336**	$ 312
Less: Retained interests	**93**	87	**118**	106
Net receivables sold	**$ 176**	$ 186	**$ 218**	$ 206

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)	2018	2017	2016	2018	2017	2016
Sales						
Receivables sold	**$ 1,987**	$ 1,879	$ 1,926	**$ 2,842**	$ 2,711	$ 2,635
Loss recognized on sale	**13**	10	9	**16**	12	11
Cash Flows						
Cash proceeds from receivables sold	**1,967**	1,865	1,882	**2,815**	2,694	2,583
Collection fees received	**1**	1	1	**1**	1	1
Return received on retained interests	**6**	3	2	**9**	7	5

Cash flows from the sales of receivables are reflected within Cash Flows From Operating Activities on Duke Energy Ohio's and Duke Energy Indiana's Consolidated Statements of Cash Flows.

Collection fees received in connection with servicing transferred accounts receivable are included in Operation, maintenance and other on Duke Energy Ohio's and Duke Energy Indiana's Consolidated Statements of Operations and Comprehensive Income. The loss recognized on sales of receivables is calculated monthly by multiplying receivables sold during the month by the required discount. The required discount is derived monthly utilizing a three-year weighted average formula that considers charge-off history, late charge history and turnover history on the sold receivables, as well as a component for the time value of money. The discount rate, or component for the time value of money, is the prior month-end LIBOR plus a fixed rate of 1.00 percent.

18. REVENUE

As described in Note 1, Duke Energy adopted Revenue from Contracts with Customers effective January 1, 2018, using the modified retrospective method of adoption, which does not require restatement of prior year reported results. No cumulative effect adjustment was recorded as the vast majority of Duke Energy's revenues are at-will and without a defined contractual term. Additionally, comparative disclosures for 2018 operating results with the previous revenue recognition rules are not applicable as Duke Energy's revenue recognition has not materially changed as a result of the new standard.

Duke Energy recognizes revenue consistent with amounts billed under tariff offerings or at contractually agreed upon rates based on actual physical delivery of electric or natural gas service, including estimated volumes delivered when billings have not yet occurred. As such, the majority of Duke Energy's revenues have fixed pricing based on the contractual terms of the published tariffs, with variability in expected cash flows attributable to the customer's volumetric demand and ultimate quantities of energy or natural gas supplied and used during the billing period. The stand-alone selling price of related sales are designed to support recovery of prudently incurred costs and an appropriate return on invested assets and are primarily governed by published tariff rates or contractual agreements approved by relevant regulatory bodies. As described in Note 1, certain excise taxes and franchise fees 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 as part of revenues. Duke Energy elects to account for all other taxes net of revenues.

Performance obligations are satisfied over time as energy or natural gas is delivered and consumed with billings generally occurring monthly and related payments due within 30 days, depending on regulatory requirements. In no event does the timing between payment and delivery of the goods and services exceed one year. Using this output method for revenue recognition provides a faithful depiction of the transfer of electric and natural gas service as customers obtain control of the commodity and benefit from its use at delivery. Additionally, Duke Energy has an enforceable right to consideration for energy or natural gas delivered at any discrete point in time, and will recognize revenue at an amount that reflects the consideration to which Duke Energy is entitled for the energy or natural gas delivered.

As described above, the majority of Duke Energy’s tariff revenues are at-will and, as such, related contracts with customers have an expected duration of one year or less and will not have future performance obligations for disclosure. Additionally, other long-term revenue streams, including wholesale contracts, generally provide services that are part of a single performance obligation, the delivery of electricity or natural gas. As such, other than material fixed consideration under long-term contracts, related disclosures for future performance obligations are also not applicable.

Duke Energy earns substantially all of its revenues through its reportable segments, Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

Electric Utilities and Infrastructure

Electric Utilities and Infrastructure earns the majority of its revenues through retail and wholesale electric service through the generation, transmission, distribution and sale of electricity. Duke Energy generally provides retail and wholesale electric service customers with their full electric load requirements or with supplemental load requirements when the customer has other sources of electricity.

Retail electric service is generally marketed throughout Duke Energy's electric service territory through standard service offers. The standard service offers are through tariffs determined by regulators in Duke Energy's regulated service territory. Each tariff, which is assigned to customers based on customer class, has multiple components such as an energy charge, a demand charge, a basic facilities charge and applicable riders. Duke Energy considers each of these components to be aggregated into a single performance obligation for providing electric service, or in the case of distribution only customers in Duke Energy Ohio, for delivering electricity. Electricity is considered a single performance obligation satisfied over time consistent with the series guidance and is provided and consumed over the billing period, generally one month. Retail electric service is typically provided to at-will customers who can cancel service at any time, without a substantive penalty. Additionally, Duke Energy adheres to applicable regulatory requirements in each jurisdiction to ensure the collectability of amounts billed and appropriate mitigating procedures are followed when necessary. As such, revenue from contracts with customers for such contracts is equivalent to the electricity supplied and billed in that period (including unbilled estimates).

Wholesale electric service is generally provided under long-term contracts using cost-based pricing. FERC regulates costs that may be recovered from customers and the amount of return companies are permitted to earn. Wholesale contracts include both energy and demand charges. For full requirements contracts, Duke Energy considers both charges as a single performance obligation for providing integrated electric service. For contracts where energy and demand charges are considered separate performance obligations, energy and demand are each a distinct performance obligation under the series guidance and are satisfied as energy is delivered and stand-ready service is provided on a monthly basis. This service represents consumption over the billing period and revenue is recognized consistent with billings and unbilled estimates, which generally occur monthly. Contractual amounts owed are typically trued up annually based upon incurred costs in accordance with FERC published filings and the specific customer’s actual peak demand. Estimates of variable consideration related to potential additional billings or refunds owed are updated quarterly.

The majority of wholesale revenues are full requirements contracts where the customers purchase the substantial majority of their energy needs and do not have a fixed quantity of contractually required energy or capacity. As such, related forecasted revenues are considered optional purchases. Supplemental requirements contracts that include contracted blocks of energy and capacity at contractually fixed prices have the following estimated remaining performance obligations:

	Remaining Performance Obligations						
(in millions)	2019	2020	2021	2022	2023	Thereafter	Total
Progress Energy	$ 112	$ 121	$ 80	$ 82	$ 39	$ 42	$ 476
Duke Energy Progress	9	9	9	9	9	9	54
Duke Energy Florida	103	112	71	73	30	33	422
Duke Energy Indiana	9	10	5	—	—	—	24

Revenues for block sales are recognized monthly as energy is delivered and stand-ready service is provided, consistent with invoiced amounts and unbilled estimates.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure earns its revenue through retail and wholesale natural gas service through the transportation, distribution and sale of natural gas. Duke Energy generally provides retail and wholesale natural gas service customers with all natural gas load requirements. Additionally, while natural gas can be stored, substantially all natural gas provided by Duke Energy is consumed by customers simultaneously with receipt of delivery.

Retail natural gas service is marketed throughout Duke Energy's natural gas service territory using published tariff rates. The tariff rates are established by regulators in Duke Energy's service territories. Each tariff, which is assigned to customers based on customer class, have multiple components, such as a commodity charge, demand charge, customer or monthly charge and transportation costs. Duke Energy considers each of these components to be aggregated into a single performance obligation for providing natural gas service. For contracts where Duke Energy provides all of the customer’s natural gas needs, the delivery of natural gas is considered a single performance obligation satisfied over time, and revenue is recognized monthly based on billings and unbilled estimates as service is provided and the commodity is consumed over the billing period. Additionally, natural gas service is typically at-will and customers can cancel service at any time, without a substantive penalty. Duke Energy also adheres to applicable regulatory requirements to ensure the collectability of amounts billed and receivable and appropriate mitigating procedures are followed when necessary.

Certain long-term individually negotiated contracts exist to provide natural gas service. These contracts are regulated and approved by state commissions. The negotiated contracts have multiple components, including a natural gas and a demand charge, similar to retail natural gas contracts. Duke Energy considers each of these components to be a single performance obligation for providing natural gas service. This service represents consumption over the billing period, generally one month.

Fixed capacity payments under long-term contracts for the Gas Utilities and Infrastructure segment include minimum margin contracts and supply arrangements with municipalities and power generation facilities. Revenues for related sales are recognized monthly as natural gas is delivered and stand-ready service is provided, consistent with invoiced amounts and unbilled estimates. Estimated remaining performance obligations are as follows:

	Remaining Performance Obligations						
(in millions)	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Piedmont	$ 70	$ 68	$ 63	$ 63	$ 60	$ 430	$ 754

Commercial Renewables

Commercial Renewables earns the majority of its revenues through long-term PPAs and generally sells all of its wind and solar facility output, electricity and RECs to customers. The majority of these PPAs have historically been accounted for as leases. For PPAs that are not accounted for as leases, the delivery of electricity and the delivery of RECs are considered separate performance obligations.

The delivery of electricity is a performance obligation satisfied over time and represents generation and consumption of the electricity over the billing period, generally one month. The delivery of RECs is a performance obligation satisfied at a point in time and represents delivery of each REC generated by the wind or solar facility. The majority of self-generated RECs are bundled with energy in Duke Energy’s contracts and, as such, related revenues are recognized as energy is generated and delivered as that pattern is consistent with Duke Energy’s performance. Commercial Renewables recognizes revenue based on the energy generated and billed for the period, generally one month, at contractual rates (including unbilled estimates) according to the invoice practical expedient. Amounts are typically due within 30 days of invoice.

Commercial Renewables also earns revenues from installation of distributed solar generation resources, which is primarily composed of EPC projects to deliver functioning solar power systems, generally completed within two to 12 months from commencement of construction. The installation of distributed solar generation resources is a performance obligation that is satisfied over time. Revenue from fixed-price EPC contracts is recognized using the input method as work is performed based on the estimated ratio of incurred costs to estimated total costs.

Other

The remainder of Duke Energy’s operations is presented as Other, which does not include material revenues from contracts with customers.

Disaggregated Revenues

For the Electric and Gas Utility and Infrastructure segments, revenue by customer class is most meaningful to Duke Energy as each respective customer class collectively represents unique customer expectations of service, generally has different energy and demand requirements, and operates under tailored, regulatory approved pricing structures. Additionally, each customer class is impacted differently by weather and a variety of economic factors including the level of population growth, economic investment, employment levels, and regulatory activities in each of Duke Energy's jurisdictions. As such, analyzing revenues disaggregated by customer class allows Duke Energy to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For the Commercial Renewables segment, the majority of revenues from contracts with customers are from selling all of the unit-contingent output at contractually defined pricing under long-term PPAs with consistent expectations regarding the timing and certainty of cash flows. Disaggregated revenues are presented as follows:

	Year Ended December 31, 2018							
(in millions) By market or type of customer	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electric Utilities and Infrastructure								
Residential	$ **9,587**	$ **2,981**	$ **4,785**	$ **2,019**	$ **2,766**	$ **743**	$ **1,076**	$ **—**
General	**6,127**	**2,119**	**2,809**	**1,280**	**1,529**	**422**	**778**	**—**
Industrial	**2,974**	**1,180**	**904**	**642**	**262**	**131**	**760**	**—**
Wholesale	**2,324**	**508**	**1,462**	**1,303**	**159**	**57**	**298**	**—**
Other revenues	**717**	**320**	**502**	**320**	**182**	**73**	**91**	**—**
Total Electric Utilities and Infrastructure								

revenue from contracts with customers	$	21,729	$	7,108	$	10,462	$	5,564	$	4,898	$	1,426	$	3,003	$	—
Gas Utilities and Infrastructure																
Residential	$	1,000	$	—	$	—	$	—	$	—	$	331	$	—	$	669
Commercial		514		—		—		—		—		135		—		378
Industrial		147		—		—		—		—		18		—		128
Power Generation		—		—		—		—		—		—		—		54
Other revenues		139		—		—		—		—		19		—		120
Total Gas Utilities and Infrastructure revenue from contracts with customers	$	1,800	$	—	$	—	$	—	$	—	$	503	$	—	$	1,349
Commercial Renewables																
Revenue from contracts with customers	$	209	$	—	$	—	$	—	$	—	$	—	$	—	$	—
Other																
Revenue from contracts with customers	$	19	$	—	$	—	$	—	$	—	$	1	$	—	$	—
Total revenue from contracts with customers	$	23,757	$	7,108	$	10,462	$	5,564	$	4,898	$	1,930	$	3,003	$	1,349
Other revenue sources(a)	$	764	$	192	$	266	$	135	$	123	$	27	$	56	$	26
Total revenues	$	24,521	$	7,300	$	10,728	$	5,699	$	5,021	$	1,957	$	3,059	$	1,375

(a) Other revenue sources include revenues from leases, derivatives and alternative revenue programs that are not considered revenues from contracts with customers. Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over or under collection of related revenues.

IMPACT OF WEATHER AND THE TIMING OF BILLING PERIODS

Revenues and costs are influenced by seasonal weather patterns. Peak sales of electricity occur during the summer and winter months, which results in higher revenue and cash flows during these periods. By contrast, lower sales of electricity occur during the spring and fall, allowing for scheduled plant maintenance. Residential and general service customers are more impacted by weather than industrial customers. Estimated weather impacts are based on actual current period weather compared to normal weather conditions. Normal weather conditions are defined as the long-term average of actual historical weather conditions. Heating-degree days measure the variation in weather based on the extent the average daily temperature falls below a base temperature. Cooling-degree days measure the variation in weather based on the extent the average daily temperature rises above the base temperature. Each degree of temperature below the base temperature counts as one heating-degree day and each degree of temperature above the base temperature counts as one cooling-degree day.

The estimated impact of weather on earnings for Electric Utilities and Infrastructure is based on the temperature variances from a normal condition and customers' historic usage patterns. The methodology used to estimate the impact of weather does not consider all variables that may impact customer response to weather conditions, such as humidity in the summer or wind chill in the winter. The precision of this estimate may also be impacted by applying long-term weather trends to shorter-term periods.

Gas Utilities and Infrastructure's costs and revenues are influenced by seasonal patterns due to peak natural gas sales occurring during the winter months as a result of space heating requirements. Residential customers are the most impacted by weather. There are certain regulatory mechanisms for the North Carolina, South Carolina, Tennessee and Ohio service territories that normalize the margins collected from certain customer classes during the winter. In North Carolina, rate design provides protection from both weather and other usage variations such as conservation, while South Carolina and Tennessee revenues are adjusted solely based on weather. Ohio primarily employs a fixed charge each month regardless of the season and usage.

UNBILLED REVENUE

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

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

	December 31,	
(in millions)	**2018**	**2017**
Duke Energy	**$ 896**	$ 944
Duke Energy Carolinas	**313**	342
Progress Energy	**244**	228
Duke Energy Progress	**148**	143
Duke Energy Florida	**96**	85
Duke Energy Ohio	**2**	4
Duke Energy Indiana	**23**	21
Piedmont	**73**	86

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, CRC and accounts 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)	**2018**	**2017**
Duke Energy Ohio	**$ 86**	$ 104
Duke Energy Indiana	**128**	132

19. COMMON STOCK

Basic EPS is computed by dividing net income attributable to Duke Energy common stockholders, as adjusted for distributed and undistributed earnings allocated to participating securities, by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to Duke Energy common stockholders, as adjusted for distributed and undistributed earnings allocated to participating securities, by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common shares, such as stock options and equity forward sale agreements, were exercised or settled. Duke Energy’s participating securities are restricted stock units that are entitled to dividends declared on Duke Energy common stock during the restricted stock unit’s vesting periods.

The following table presents Duke Energy’s basic and diluted EPS calculations and reconciles the weighted average number of common stock outstanding to the diluted weighted average number of common stock outstanding.

	Years Ended December 31,		
(in millions, except per share amounts)	**2018**	**2017**	**2016**
Income from continuing operations attributable to Duke Energy common stockholders excluding impact of participating securities	**$ 2,642**	$ 3,059	$ 2,567
Weighted average shares outstanding – basic	**708**	700	691

Weighted average shares outstanding – diluted		**708**		700		691
Earnings per share from continuing operations attributable to Duke Energy common stockholders						
Basic	**$**	**3.73**	$	4.37	$	3.71
Diluted	**$**	**3.73**	$	4.37	$	3.71
Potentially dilutive items excluded from the calculation[(a)]		**2**		2		2
Dividends declared per common share	**$**	**3.64**	$	3.49	$	3.36

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

Equity Issuances

On February 20, 2018, Duke Energy filed a prospectus supplement and executed an EDA under which it may sell up to $1 billion of its common stock through an ATM offering program, including an equity forward sales component. The EDA was entered into with Wells Fargo Securities, LLC, Citigroup Global Markets Inc., and J.P. Morgan Securities LLC (the Agents). Under the terms of the EDA, Duke Energy may issue and sell, through any of the Agents, shares of common stock during the period ending September 23, 2019. In June 2018, Duke Energy marketed two separate tranches, each for 1.3 million shares, of common stock. The first tranche was marketed with Wells Fargo Bank at an initial forward price of $72.02 per share and the second tranche was marketed with Citibank at an initial forward price of $78.71 per share through equity forward transactions under the ATM program. The Equity Forwards require Duke Energy to either physically settle the transactions by issuing 2.6 million shares in exchange for net proceeds at the then-applicable forward sale price specified by the agreements or net settle in whole or in part through the delivery or receipt of cash or shares. The settlement alternative was at Duke Energy's election. In December 2018, Duke Energy physically settled these equity forwards by delivering 2.6 million shares of common stock in exchange for net proceeds of approximately $195 million.

Separately, in March 2018, Duke Energy marketed an equity offering of 21.3 million shares of common stock through an Underwriting Agreement with Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Barclays Capital Inc. and Goldman Sachs & Co. LLC, as representatives of several underwriters, Credit Suisse Capital LLC and J.P. Morgan Securities LLC as Forward Sellers, and Credit Suisse Capital LLC and J.P. Morgan Chase Bank, National Association, acting as forward purchasers. In connection with the offering, Duke Energy entered into equity forward sale agreements with Credit Suisse Securities (USA) LLC as Agent for Credit Suisse Capital LLC and J.P. Morgan Chase Bank, National Association. The sale price was $75 per share less certain net adjustments for an initial forward price of $74.07 per share. The Equity Forwards require Duke Energy to either physically settle the transactions by issuing 21.3 million shares in exchange for net proceeds at the then-applicable forward sale price specified by the agreements, or net settle in whole or in part through the delivery or receipt of cash or shares. The settlement alternative was at Duke Energy's election. In June 2018, Duke Energy physically settled one-half of the equity forwards by delivering approximately 10.6 million shares of common stock in exchange for net cash proceeds of approximately $781 million. In December 2018, Duke Energy physically settled the remaining equity forward by delivering 10.6 million shares of common stock in exchange for net cash proceeds of approximately $766 million.

For the year ended December 31, 2018, Duke Energy issued 2.2 million shares through its DRIP with an increase in additional paid-in capital of approximately $174 million.

In March 2016, Duke Energy marketed an equity offering of 10.6 million shares of common stock. In lieu of issuing equity at the time of the offering, Duke Energy entered into Equity Forwards with Barclays. The Equity Forwards required Duke Energy to either physically settle the transactions by issuing 10.6 million shares, or net settle in whole or in part through the delivery or receipt of cash or shares. On October 5, 2016, following the close of the Piedmont acquisition, Duke Energy physically settled the Equity Forwards in full by delivering 10.6 million shares of common stock in exchange for net cash proceeds of approximately $723 million. The net proceeds were used to finance a portion of the Piedmont acquisition. As a result of the acquisition, all of Piedmont's issued and outstanding stock became the issued and outstanding shares of a wholly owned subsidiary of Duke Energy. See Note 2 for additional information related to the Piedmont acquisition.

20. SEVERANCE

During 2018, Duke Energy reviewed its operations and identified opportunities for improvement to better serve its customers. This operational review included the company's workforce strategy and staffing levels to ensure the company is staffed with the right skillsets and number of teammates to execute the long-term vision for Duke Energy. As such, Duke Energy extended voluntary and involuntary severance benefits to certain employees in specific areas as a part of workforce planning and digital transformation efforts.

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 continued into 2017 and were a part of the synergies expected to be realized with the acquisition. Refer to Note 2 for additional information on the Piedmont acquisition.

Severance benefit charges for initiatives and plans discussed above were accrued for a total of approximately 1,900 employees in 2018, 100 employees in 2017 and 600 employees in 2016. The following table presents the direct and allocated severance and related charges recorded by the Duke Energy Registrants. Amounts are included within Operation, maintenance and other on the Consolidated Statements of Operations.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont(a)
Year Ended December 31, 2018	**$ 187**	**$ 102**	**$ 69**	**$ 52**	**$ 17**	**$ 6**	**$ 7**	**$ 2**
Year Ended December 31, 2017	15	2	2	1	1	—	1	9
Year Ended December 31, 2016	118	39	40	23	17	3	7	

(a) Piedmont severance benefit charges were $3 million for the two months ended December 31, 2016, and $19 million for the year ended October 31, 2016.

The table below presents the severance liability for past and ongoing severance plans including the plans described above.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Balance at December 31, 2017	$ 19	$ 5	$ 2	$ 1	$ —	$ —	$ —	$ 5
Provision/Adjustments	**200**	**98**	**50**	**40**	**10**	**2**	**2**	**—**
Cash Reductions	**(14)**	**(3)**	**(1)**	**—**	**(1)**	**—**	**—**	**(5)**
Balance at December 31, 2018	**$ 205**	**$ 100**	**$ 51**	**$ 41**	**$ 9**	**$ 2**	**$ 2**	**—**

21. STOCK-BASED COMPENSATION

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)	2018	2017	2016
Duke Energy	**$ 56**	$ 43	$ 35
Duke Energy Carolinas	**20**	15	12
Progress Energy	**21**	16	12
Duke Energy Progress	**13**	10	7

Duke Energy Florida	**8**	6	5
Duke Energy Ohio	**4**	3	2
Duke Energy Indiana	**5**	4	3
Piedmont[(a)]	**3**	3	

(a) Piedmont's stock-based compensation costs were not material for the two months ended December 31, 2016. See discussion below for information on Piedmont's pre-merger stock-based compensation plans.

Duke Energy's pretax stock-based compensation costs, the tax benefit associated with stock-based compensation expense and stock-based compensation costs capitalized are included in the following table.

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Restricted stock unit awards	**$ 43**	$ 41	$ 36
Performance awards	**35**	27	19
Pretax stock-based compensation cost	**$ 78**	$ 68	$ 55
Stock-based compensation costs capitalized	**5**	4	2
Stock-based compensation expense	**$ 73**	$ 64	$ 53
Tax benefit associated with stock-based compensation expense	**$ 17**	$ 25	$ 20

RESTRICTED STOCK UNIT AWARDS

RSU awards generally vest over periods from immediate to three years. Fair value amounts are based on the market price of Duke Energy's common stock on the grant date. The following table includes information related to RSU awards.

	Years Ended December 31,		
	2018	**2017**	**2016**
Shares awarded (in thousands)	**649**	583	684
Fair value (in millions)	**$ 49**	$ 47	$ 52

The following table summarizes information about RSU awards outstanding.

	Shares (in thousands)	**Weighted Average Grant Date Fair Value (per share)**
Outstanding at December 31, 2017	1,121	$ 78
Granted	**649**	**76**
Vested	**(545)**	**78**
Forfeited	**(72)**	**77**
Outstanding at December 31, 2018	**1,153**	**77**
Restricted stock unit awards expected to vest	**1,101**	**77**

The total grant date fair value of shares vested during the years ended December 31, 2018, 2017 and 2016, was $43 million, $42 million and $38 million, respectively. At December 31, 2018, Duke Energy had $29 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 23 months.

PERFORMANCE AWARDS

Stock-based performance awards generally vest after three years if performance targets are met. The actual number of shares issued will range from zero to 200 percent of target shares, depending on the level of performance achieved.

Performance awards contain market conditions based on relative TSR compared to a predefined peer group, as well as a performance condition based on Duke Energy's cumulative adjusted EPS. Performance awards granted in 2018 and 2017 also contain a performance condition based on the total incident case rate, one of our key employee safety metrics.

The market condition component of Duke Energy's performance awards is 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 2018, the model used a risk-free interest rate of 2.4 percent, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 16.0 percent based on Duke Energy's historical volatility over three years using daily stock prices.

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

	Years Ended December 31,		
	2018	**2017**	**2016**
Shares granted assuming target performance (in thousands)	**372**	461	338
Fair value (in millions)	**$ 27**	$ 37	$ 25

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

	Shares (in thousands)	**Weighted Average Grant Date Fair Value (per share)**
Outstanding at December 31, 2017	1,065	$ 79
Granted	**372**	**73**
Vested	**(155)**	**81**
Forfeited	**(165)**	**80**
Outstanding at December 31, 2018	**1,117**	**77**
Stock-based performance awards expected to vest	**1,086**	**77**

The total grant date fair value of shares vested during the years ended December 31, 2018, and 2016, was $13 million and $25 million, respectively. No performance awards vested during the year ended December 31, 2017. At December 31, 2018, Duke Energy had $30 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 21 months.

PIEDMONT

Prior to Duke Energy's acquisition of Piedmont, Piedmont had an incentive compensation plan that had a series of three-year performance and RSU awards for eligible officers and other participants. The Merger Agreement provided for the conversion of the 2014-2016 and 2015-2017 performance awards and the nonvested 2016 RSU award into the right to receive $60 cash per share upon the close of the transaction. In December 2015, Piedmont's board of directors authorized the accelerated vesting, payment and taxation of the 2014-2016 and 2015-2017 performance awards, as well as the 2016 RSU award, at the election of the participant. Substantially all participants elected to accelerate the settlement of these awards. As a result of the settlement of these awards, 194 thousand shares of Piedmont shares were issued to participants, net of shares withheld for applicable federal and state income taxes, at a closing price of $56.85 and a fair value of $11 million. The 2016-2018 performance award cycle was approved subsequent to the Merger Agreement and was converted into a Duke Energy RSU award at the consummation of the acquisition.

Piedmont's stock-based compensation costs and the tax benefit associated with stock-based compensation expense are included in the following table.

(in millions)	Year Ended October 31, 2016
Pretax stock-based compensation cost	$ 16
Tax benefit associated with stock-based compensation expense	6
Net of tax stock-based compensation cost	$ 10

22. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT RETIREMENT PLANS

Duke Energy and certain subsidiaries maintain, and the Subsidiary Registrants participate in, qualified, non-contributory defined benefit retirement plans. The Duke Energy plans cover most employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits based upon a percentage of current eligible earnings, age or age and years of service and interest credits. Certain employees are eligible for benefits that use a final average earnings formula. Under these final average earnings formulas, a plan participant accumulates a retirement benefit equal to the sum of percentages of their (i) highest three-year, four-year, or five-year average earnings, (ii) highest three-year, four-year, or five-year average earnings in excess of covered compensation per year of participation (maximum of 35 years) or (iii) highest three-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains, and the Subsidiary Registrants participate in, non-qualified, non-contributory defined benefit retirement plans that cover certain executives. The qualified and non-qualified, non-contributory defined benefit plans are closed to new participants.

Duke Energy approved plan amendments to restructure its qualified non-contributory defined benefit retirement plans, effective January 1, 2018. The restructuring involved (i) the spin-off of the majority of inactive participants from two plans into a separate inactive plan and (ii) the merger of the active participant portions of such plans, along with a pension plan acquired as part of the Piedmont transaction, into a single active plan. Benefits offered to the plan participants remain unchanged except that the Piedmont plan's final average earnings formula was frozen as of December 31, 2017, and affected participants were moved into the active plan's cash balance formula. Actuarial gains and losses associated with the Inactive Plan will be amortized over the remaining life expectancy of the inactive participants. The longer amortization period lowered Duke Energy's 2018 pretax qualified pension plan expense by approximately $33 million.

Duke Energy uses a December 31 measurement date for its defined benefit retirement plan assets and obligations.

Net periodic benefit costs disclosed in the tables below represent the cost of the respective benefit plan for the periods presented prior to capitalization of amounts reflected as Net property, plant and equipment, on the Consolidated Balance Sheets. Only the service cost component of net periodic benefit costs is eligible to be capitalized. The remaining non-capitalized portions of net periodic benefit costs are classified as either: (1) service cost, which is recorded in Operations, maintenance and other on the Consolidated Statements of Operations; or as (2) components of non-service cost, which is recorded in Other income and expenses, net, on the Consolidated Statements of Operations. 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 Consolidated Statements of Operations of the Subsidiary Registrants also include allocated net periodic benefit costs for 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. However, in the tables below, these amounts are only presented within the Duke Energy column. 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. Duke Energy does not anticipate making any contributions in 2019. The following table includes information related to the Duke Energy Registrants' contributions to its qualified defined benefit pension plans.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont[(a)]
Contributions Made:								
2018	$ **141**	$ **46**	$ **45**	$ **25**	$ **20**	$ **—**	$ **8**	$ **—**
2017	19	—	—	—	—	4	—	11
2016	155	43	43	24	20	5	9	

(a) Piedmont contributed $10 million to its U.S. qualified defined benefit pension plan during the two months ended December 31, 2016, and $10 million for the year ended October 31, 2016.

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ **182**	$ **58**	$ **51**	$ **29**	$ **22**	$ **5**	$ **11**	$ **7**
Interest cost on projected benefit obligation	**299**	**72**	**94**	**43**	**50**	**17**	**23**	**11**
Expected return on plan assets	**(559)**	**(147)**	**(178)**	**(85)**	**(91)**	**(28)**	**(42)**	**(22)**
Amortization of actuarial loss	**132**	**29**	**44**	**21**	**23**	**5**	**10**	**11**
Amortization of prior service credit	**(32)**	**(8)**	**(3)**	**(2)**	**(1)**	**—**	**(2)**	**(10)**
Net periodic pension costs[(a)(b)]	$ **22**	$ **4**	$ **8**	$ **6**	$ **3**	$ **(1)**	$ **—**	$ **(3)**

	Year Ended December 31, 2017						
Duke	Duke Energy	Progress	Duke Energy	Duke Energy	Duke Energy	Duke Energy	

(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Service cost	$ 159	$ 48	$ 45	$ 26	$ 19	$ 4	$ 9	$ 10
Interest cost on projected benefit obligation	328	79	100	47	53	18	26	14
Expected return on plan assets	(545)	(142)	(167)	(82)	(85)	(27)	(42)	(24)
Amortization of actuarial loss	146	31	52	23	29	5	12	11
Amortization of prior service credit	(24)	(8)	(3)	(2)	(1)	(1)	(2)	(2)
Settlement charge	12	—	—	—	—	—	—	12
Other	8	2	2	1	1	—	1	1
Net periodic pension costs(a)(b)	$ 84	$ 10	$ 29	$ 13	$ 16	$ (1)	$ 4	$ 22

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Service cost	$ 147	$ 48	$ 42	$ 24	$ 19	$ 4	$ 9
Interest cost on projected benefit obligation	335	86	106	49	55	19	28
Expected return on plan assets	(519)	(142)	(168)	(82)	(84)	(27)	(42)
Amortization of actuarial loss	134	33	51	23	29	4	11
Amortization of prior service credit	(17)	(8)	(3)	(2)	(1)	—	(1)
Settlement charge	3	—	—	—	—	—	—
Other	8	2	3	1	1	1	1
Net periodic pension costs(a)(b)	$ 91	$ 19	$ 31	$ 13	$ 19	$ 1	$ 6

(a) Duke Energy amounts exclude $5 million, $7 million and $8 million for the years ended December 2018, 2017 and 2016, 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 $4 million for the years ended December 2018, 2017 and 2016, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

	Piedmont	
	Two Months Ended	Year Ended
(in millions)	December 31, 2016	October 31, 2016
Service cost	$ 2	$ 11
Interest cost on projected benefit obligation	2	9
Expected return on plan assets	(4)	(24)
Amortization of actuarial loss	2	8
Amortization of prior service credit	(1)	(2)
Settlement charge	3	—
Net periodic pension costs	$ 4	$ 2

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	Year Ended December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Regulatory assets, net increase (decrease)	**$ 298**	**$ 170**	**$ 40**	**$ 31**	**$ 9**	**$ 10**	**$ 30**	**$ 8**
Accumulated other comprehensive loss (income)								
Deferred income tax expense	**$ (2)**	**—**	**1**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year service credit	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year actuarial losses	**10**	**—**	**(4)**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ 9**	**$ —**	**$ (3)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net (decrease) increase	$ (212)	$ (70)	$ (49)	$ (37)	$ (11)	$ 9	$ (19)	$ (64)
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ —	$ —	$ 3	$ —	$ —	$ —	$ —	$ —
Prior year service credit arising during the year	1	—	—	—	—	—	—	—
Amortization of prior year actuarial losses	(7)	—	(7)	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (6)	$ —	$ (4)	$ —	$ —	$ —	$ —	$ —

Piedmont's regulatory asset net increase was $34 million and $35 million for the two months ended December 31, 2016, and for the year ended October 31, 2016, respectively.

Reconciliation of Funded Status to Net Amount Recognized

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Obligation at prior measurement date	**$ 8,448**	**$ 2,029**	**$ 2,637**	**$ 1,211**	**$ 1,410**	**$ 479**	**$ 669**	**$ 313**
Service cost	**174**	**56**	**49**	**28**	**21**	**5**	**10**	**7**
Interest cost	**299**	**72**	**94**	**43**	**50**	**17**	**23**	**11**
Actuarial gain	**(485)**	**(44)**	**(204)**	**(87)**	**(114)**	**(29)**	**(29)**	**(18)**
Transfers	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(16)**
Benefits paid	**(567)**	**(159)**	**(143)**	**(70)**	**(72)**	**(37)**	**(55)**	**(33)**
Obligation at measurement date	**$ 7,869**	**$ 1,954**	**$ 2,433**	**$ 1,125**	**$ 1,295**	**$ 435**	**$ 618**	**$ 264**
Accumulated Benefit Obligation at measurement date	**$ 7,818**	**$ 1,954**	**$ 2,404**	**$ 1,125**	**$ 1,265**	**$ 425**	**$ 614**	**$ 264**

Change in Fair Value of Plan Assets																
Plan assets at prior measurement date	**$**	**9,003**	**$**	**2,372**	**$**	**2,814**	**$**	**1,366**	**$**	**1,429**	**$**	**458**	**$**	**684**	**$**	**368**
Employer contributions		**141**		**46**		**45**		**25**		**20**		**—**		**8**		**—**
Actual return on plan assets		**(344)**		**(91)**		**(110)**		**(53)**		**(55)**		**(16)**		**(26)**		**(14)**
Benefits paid		**(567)**		**(159)**		**(143)**		**(70)**		**(72)**		**(37)**		**(55)**		**(33)**
Transfers		**—**		**—**		**—**		**—**		**—**		**—**		**—**		**(16)**
Plan assets at measurement date	**$**	**8,233**	**$**	**2,168**	**$**	**2,606**	**$**	**1,268**	**$**	**1,322**	**$**	**405**	**$**	**611**	**$**	**305**
Funded status of plan	**$**	**364**	**$**	**214**	**$**	**173**	**$**	**143**	**$**	**27**	**$**	**(30)**	**$**	**(7)**	**$**	**41**

	Year Ended December 31, 2017															
(in millions)		**Duke Energy**		**Duke Energy Carolinas**		**Progress Energy**		**Duke Energy Progress**		**Duke Energy Florida**		**Duke Energy Ohio**		**Duke Energy Indiana**		**Piedmont**
Change in Projected Benefit Obligation																
Obligation at prior measurement date	$	8,131	$	1,952	$	2,512	$	1,158	$	1,323	$	447	$	658	$	344
Service cost		159		48		45		26		19		4		9		10
Interest cost		328		79		100		47		53		18		26		14
Actuarial loss		455		68		158		57		99		35		26		38
Transfers		—		27		(32)		(2)		(15)		12		—		—
Plan amendments		(61)		—		—		—		—		—		—		(61)
Benefits paid		(537)		(145)		(146)		(75)		(69)		(37)		(50)		(5)
Benefits paid — settlements		(27)		—		—		—		—		—		—		(27)
Obligation at measurement date	$	8,448	$	2,029	$	2,637	$	1,211	$	1,410	$	479	$	669	$	313

Accumulated Benefit Obligation at measurement date	$ 8,369	$ 2,029	$ 2,601	$ 1,211	$ 1,375	$ 468	$ 652	$ 313
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 8,531	$ 2,225	$ 2,675	$ 1,290	$ 1,352	$ 428	$ 657	$ 346
Employer contributions	19	—	—	—	—	4	—	11
Actual return on plan assets	1,017	265	317	153	161	51	77	43
Benefits paid	(537)	(145)	(146)	(75)	(69)	(37)	(50)	(5)
Benefits paid — settlements	(27)	—	—	—	—	—	—	(27)
Transfers	—	27	(32)	(2)	(15)	12	—	—
Plan assets at measurement date	$ 9,003	$ 2,372	$ 2,814	$ 1,366	$ 1,429	$ 458	$ 684	$ 368
Funded status of plan	$ 555	$ 343	$ 177	$ 155	$ 19	$ (21)	$ 15	$ 55

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Prefunded pension[a]	**$ 433**	**$ 214**	**$ 242**	**$ 143**	**$ 96**	**$ 24**	**$ 39**	**$ 41**
Noncurrent pension liability[b]	**$ 69**	**$ —**	**$ 69**	**$ —**	**$ 69**	**$ 54**	**$ 46**	**$ —**
Net asset (liability) recognized	**$ 364**	**$ 214**	**$ 173**	**$ 143**	**$ 27**	**$ (30)**	**$ (7)**	**$ 41**
Regulatory assets	**$ 2,184**	**$ 576**	**$ 796**	**$ 372**	**$ 424**	**$ 100**	**$ 182**	**$ 81**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ (43)**	**$ —**	**$ (2)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Prior service credit	**(4)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Net actuarial loss	**126**	**—**	**5**	**—**	**—**	**—**	**—**	**—**
Net amounts recognized in accumulated other comprehensive loss	**$ 79**	**$ —**	**$ 3**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	**$ 97**	**$ 22**	**$ 37**	**$ 13**	**$ 24**	**$ 3**	**$ 5**	**$ 7**
Unrecognized prior service credit	**(32)**	**(8)**	**(3)**	**(2)**	**(1)**	**—**	**(2)**	**(9)**

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Prefunded pension[a]	$ 680	$ 343	$ 245	$ 155	$ 87	$ 8	$ 16	$ 55
Noncurrent pension liability[b]	$ 125	$ —	$ 68	$ —	$ 68	$ 29	$ 1	$ —
Net asset recognized	$ 555	$ 343	$ 177	$ 155	$ 19	$ (21)	$ 15	$ 55
Regulatory assets	$ 1,886	$ 406	$ 756	$ 341	$ 415	$ 90	$ 152	$ 73
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (41)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(5)	—	—	—	—	—	—	—
Net actuarial loss	116	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 70	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 132	$ 29	$ 44	$ 21	$ 23	$ 5	$ 7	$ 11
Unrecognized prior service credit	$ (32)	$ (8)	$ (3)	$ (2)	$ (1)	$ —	$ (2)	$ (9)

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

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

	December 31, 2018				
(in millions)	**Duke Energy**	**Progress Energy**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Projected benefit obligation	**$ 679**	**$ 679**	**$ 679**	**$ 123**	**$ 203**
Accumulated benefit obligation	**651**	**651**	**651**	**115**	**199**
Fair value of plan assets	**610**	**610**	**610**	**69**	**159**

December 31, 2017			
Duke	**Progress**	**Duke Energy**	**Duke Energy**

(in millions)	Energy	Energy	Florida	Ohio
Projected benefit obligation	$ 1,386	$ 718	$ 718	$ 337
Accumulated benefit obligation	1,326	683	683	326
Fair value of plan assets	1,260	650	650	308

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 for participants in active plans and life expectancy of participants in inactive plans is 13 years for Duke Energy and Duke Energy Progress, 12 years for Duke Energy Carolinas, Progress Energy, and Duke Energy Florida, 14 years for Duke Energy Ohio and Duke Energy Indiana, and 10 years for Piedmont.

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

	December 31,		
	2018	**2017**	**2016**
Benefit Obligations			
Discount rate	**4.30%**	3.60%	4.10%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	4.00% – 4.50%
Net Periodic Benefit Cost			
Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.00% – 4.50%	4.00% – 4.40%
Expected long-term rate of return on plan assets	**6.50%**	6.50% – 6.75%	6.50% – 6.75%

	Piedmont	
	Two Months Ended	**Year Ended**

	December 31, 2016	October 31, 2016
Benefit Obligations		
Discount rate	4.10%	3.80%
Salary increase	4.50%	4.05%
Net Periodic Benefit Cost		
Discount rate	3.80%	4.34%
Salary increase	4.05%	4.07%
Expected long-term rate of return on plan assets	6.75%	7.25%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2019	$ 662	$ 210	$ 179	$ 105	$ 73	$ 33	$ 47	$ 20
2020	651	177	171	90	80	37	51	24
2021	663	182	177	95	81	37	51	23
2022	662	189	179	94	84	37	49	22
2023	655	185	181	95	85	35	47	22
2024-2028	2,993	794	902	451	447	158	217	96

NON-QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2018				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Service cost	$ 2	$ 1	$ —	$ —	$ —
Interest cost on projected benefit obligation	12	—	4	1	2
Amortization of actuarial loss	8	—	2	1	1
Amortization of prior service credit	(2)	—	—	—	—
Net periodic pension costs	$ 20	$ 1	$ 6	$ 2	$ 3

	Year Ended December 31, 2017				
		Duke		Duke	Duke

(in millions)		Duke Energy	Energy Carolinas	Progress Energy	Energy Progress	Energy Florida
Service cost	$	2 $	1 $	— $	— $	—
Interest cost on projected benefit obligation		13	1	5	1	2
Amortization of actuarial loss		8	—	2	1	1
Amortization of prior service credit		(2)	—	—	—	—
Net periodic pension costs	$	21 $	2 $	7 $	2 $	3

		Year Ended December 31, 2016				
(in millions)		Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
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

(in millions)		Piedmont Year Ended October 31, 2016
Amortization of prior service cost	$	—
Settlement charge		1
Net periodic pension costs	$	1

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

		Year Ended December 31, 2018				
(in millions)		Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Regulatory assets, net (decrease) increase	$	(16)$	1 $	(6)$	(3)$	(3)
Accumulated other comprehensive (income) loss						
Deferred income tax benefit	$	1 $	— $	1 $	— $	—
Actuarial gain arising during the year		(4)	—	(3)	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$	(3)$	— $	(2)$	— $	—

	Year Ended December 31, 2017				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida

Regulatory assets, net increase (decrease)	$ 5	$ (1)	$ 3	$ 1	$ 2
Accumulated other comprehensive (income) loss					
Prior service credit arising during the year	$ (1)	$ —	$ —	$ —	$ —
Actuarial loss arising during the year	2	—	—	—	—
Net amount recognized in accumulated other comprehensive loss (income)	$ 1	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Obligation at prior measurement date	**$ 331**	**$ 14**	**$ 116**	**$ 35**	**$ 47**	**$ 4**	**$ 3**	**$ 4**
Service cost	**2**	**1**	**—**	**—**	**—**	**—**	**—**	**—**
Interest cost	**12**	**—**	**4**	**1**	**2**	**—**	**—**	**—**
Actuarial gain	**(17)**	**—**	**(6)**	**(2)**	**(3)**	**(1)**	**—**	**(1)**
Benefits paid	**(24)**	**(1)**	**(8)**	**(3)**	**(3)**	**—**	**—**	**—**
Obligation at measurement date	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Accumulated Benefit Obligation at measurement date	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Change in Fair Value of Plan Assets								

Benefits paid	$	**(24)**	$	**(1)**	$	**(8)**	$	**(3)**	$	**(3)**	$	**—**	$	**—**	$	**—**
Employer contributions		**24**		**1**		**8**		**3**		**3**		**—**		**—**		**—**
Plan assets at measurement date	$	**—**	$	**—**	$	**—**	$	**—**	$	**—**	$	**—**	$	**—**	$	**—**

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 332	$ 14	$ 114	$ 33	$ 46	$ 4	$ 3	$ 4
Service cost	2	1	—	—	—	—	—	—
Interest cost	13	1	5	1	2	—	—	—
Actuarial loss (gain)	15	—	5	4	2	—	—	—
Benefits paid	(31)	(2)	(8)	(3)	(3)	—	—	—
Obligation at measurement date	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Accumulated Benefit Obligation at measurement date	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Change in Fair Value of Plan Assets								
Benefits paid	$ (31)	$ (2)	$ (8)	$ (3)	$ (3)	$ —	$ —	$ —
Employer contributions	31	2	8	3	3	—	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current pension liability(a)	**$ 21**	**$ 2**	**$ 8**	**$ 3**	**$ 3**	**$ —**	**$ —**	**$ —**
Noncurrent pension liability(b)	**283**	**12**	**98**	**28**	**40**	**3**	**3**	**3**
Total accrued pension liability	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Regulatory assets	**$ 62**	**$ 5**	**$ 15**	**$ 5**	**$ 10**	**$ 1**	**$ —**	**$ 1**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ (3)**	**$ —**	**$ (2)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Prior service credit	**(1)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net actuarial loss	**8**	**—**	**6**	**—**	**—**	**—**	**—**	**—**
Net amounts recognized in accumulated other comprehensive loss	**$ 4**	**$ —**	**$ 4**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	**$ 6**	**$ —**	**$ 2**	**$ 1**	**$ 1**	**$ —**	**$ —**	**$ —**
Unrecognized prior service credit	**(2)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current pension liability[(a)]	$ 23	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
Noncurrent pension liability[(b)]	308	12	108	32	44	4	3	4
Total accrued pension liability	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Regulatory assets	$ 78	$ 4	$ 21	$ 8	$ 13	$ 1	$ —	$ 1
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (4)	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	12	—	9	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 7	$ —	$ 6	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 8	$ —	$ 2	$ 1	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Projected benefit obligation	**$ 304**	**$ 14**	**$ 106**	**$ 31**	**$ 43**	**$ 3**	**$ 3**	**$ 3**
Accumulated benefit obligation	**304**	**14**	**106**	**31**	**43**	**3**	**3**	**3**

	December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Projected benefit obligation	$ 331	$ 14	$ 116	$ 35	$ 47	$ 4	$ 3	$ 4
Accumulated benefit obligation	331	14	116	35	47	4	3	4

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, 13 years for Progress Energy, 11 years for Duke Energy Progress, 15 years for Duke Energy Florida, eight years for Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Piedmont. The following tables present the assumptions used for pension benefit accounting.

	December 31,		
	2018	2017	2016
Benefit Obligations			
Discount rate	**4.30%**	3.60%	4.10%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	4.40%
Net Periodic Benefit Cost			

Discount rate	**3.60%**	4.10%	4.40%
Salary increase	**3.50% – 4.00%**	4.40%	4.40%

	Piedmont	
	Two Months Ended	Year Ended
	December 31, 2016	October 31, 2016
Benefit Obligations		
Discount rate	4.10%	3.80%
Net Periodic Benefit Cost		
Discount rate	3.80%	3.85%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2019	$ 22	$ 2	$ 8	$ 3	$ 3	$ —	$ —	$ —
2020	21	1	8	2	3	—	—	—
2021	23	1	8	2	3	—	—	—
2022	25	1	8	2	3	—	—	—
2023	25	3	7	2	3	—	—	—
2024-2028	125	10	37	11	15	1	1	2

OTHER POST-RETIREMENT BENEFIT PLANS

Duke Energy provides, and the Subsidiary Registrants participate in, some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The health care benefits include medical, dental and prescription drug coverage and are subject to certain limitations, such as deductibles and copayments.

Duke Energy did not make any pre-funding contributions to its other post-retirement benefit plans during the years ended December 31, 2018, 2017 or 2016.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 6	$ 1	$ 1	$ —	$ 1	$ 1	$ 1	$ 1
Interest cost on accumulated post-retirement benefit obligation	28	7	12	6	6	1	3	1
Expected return on plan assets	(13)	(8)	—	—	—	—	—	(2)

Amortization of actuarial loss	**6**	**3**	**1**	**1**	**—**	**—**	**4**	**—**
Amortization of prior service credit	**(19)**	**(5)**	**(8)**	**(1)**	**(7)**	**(1)**	**(1)**	**(2)**
Net periodic post-retirement benefit costs (a)(b)	**$ 8**	**$ (2)**	**$ 6**	**$ 6**	**$ —**	**$ 1**	**$ 7**	**$ (2)**

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Service cost	$ 4	$ 1	$ —	$ —	$ —	$ —	$ —	$ 1
Interest cost on accumulated post-retirement benefit obligation	34	8	13	7	6	1	3	1
Expected return on plan assets	(14)	(8)	—	—	—	—	(1)	(2)
Amortization of actuarial loss (gain)	10	(2)	21	12	9	(2)	(1)	1
Amortization of prior service credit	(115)	(10)	(84)	(54)	(30)	—	(1)	—
Curtailment credit (c)	(30)	(4)	(16)	—	(16)	(2)	(2)	—
Net periodic post-retirement benefit costs(a)(b)	$ (111)	$ (15)	$ (66)	$ (35)	$ (31)	$ (3)	$ (2)	$ 1

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Service cost	$ 3	$ 1	$ 1	$ —	$ 1	$ —	$ —
Interest cost on accumulated post-retirement benefit obligation	35	8	15	8	7	1	4
Expected return on plan assets	(12)	(8)	—	—	—	—	(1)
Amortization of actuarial loss (gain)	6	(3)	22	13	9	(2)	(1)
Amortization of prior service credit	(141)	(14)	(103)	(68)	(35)	—	(1)
Net periodic post-retirement benefit costs(a)(b)	$ (109)	$ (16)	$ (65)	$ (47)	$ (18)	$ (1)	$ 1

(a) Duke Energy amounts exclude $7 million, $7 million and $8 million for the years ended December 2018, 2017 and 2016, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $2 million, $2 million and $2 million for the years ended December 2018, 2017 and 2016, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(c) Curtailment credit resulted from a reduction in average future service of plan participants due to a plan amendment.

(in millions)	Piedmont Year Ended October 31, 2016
Service cost	$ 1
Interest cost on projected benefit obligation	1
Expected return on plan assets	(2)
Amortization of actuarial loss	1
Net periodic pension costs	$ 1

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

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net increase (decrease)	$ 137	$ —	$ 133	$ 84	$ 49	$ —	$ (5)	$ 4
Regulatory liabilities, net increase (decrease)	$ 154	$ (6)	$ 149	$ 93	$ 56	$ 2	$ 3	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amortization of prior year actuarial gain	1	—	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net increase (decrease)	$ 71	$ —	$ 81	$ 42	$ 39	$ —	$ (5)	$ (11)
Regulatory liabilities, net increase (decrease)	$ (27)	$ (2)	$ —	$ —	$ —	$ (3)	$ (7)	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amortization of prior year prior service credit	3	—	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 2	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Piedmont's regulatory assets net decreased $1 million for the two months ended December 31, 2016, and increased $2 million for the year ended October 31, 2016.

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

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	**$ 813**	**$ 189**	**$ 342**	**$ 184**	**$ 156**	**$ 30**	**$ 78**	**$ 32**
Service cost	**6**	**1**	**1**	**—**	**1**	**1**	**1**	**1**
Interest cost	**28**	**7**	**12**	**6**	**6**	**1**	**3**	**1**
Plan participants' contributions	**18**	**3**	**6**	**4**	**3**	**1**	**2**	**—**
Actuarial gains	**(51)**	**(8)**	**(23)**	**(9)**	**(13)**	**(2)**	**(5)**	**(1)**
Transfers	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(1)**
Benefits paid	**(86)**	**(18)**	**(35)**	**(19)**	**(16)**	**(2)**	**(12)**	**(2)**
Accumulated post-retirement benefit obligation at measurement date	**$ 728**	**$ 174**	**$ 303**	**$ 166**	**$ 137**	**$ 29**	**$ 67**	**$ 30**

Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	**$ 225**	**$ 133**	**$ —**	**$ —**	**$ —**	**$ 7**	**$ 11**	**$ 31**
Actual return on plan assets	**(8)**	**(5)**	**—**	**—**	**—**	**—**	**—**	**(1)**
Benefits paid	**(86)**	**(18)**	**(35)**	**(19)**	**(16)**	**(2)**	**(12)**	**(2)**
Employer contributions	**46**	**2**	**29**	**15**	**13**	**2**	**4**	**1**
Plan participants' contributions	**18**	**3**	**6**	**4**	**3**	**1**	**2**	**—**
Plan assets at measurement date	**$ 195**	**$ 115**	**$ —**	**$ —**	**$ —**	**$ 8**	**$ 5**	**$ 29**
Funded status of plan	**$ (533)**	**$ (59)**	**$ (303)**	**$ (166)**	**$ (137)**	**$ (21)**	**$ (62)**	**$ (1)**

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	$ 868	$ 201	$ 357	$ 191	$ 164	$ 32	$ 83	$ 39
Service cost	4	1	—	—	—	—	—	1
Interest cost	34	8	13	7	6	1	3	1
Plan participants' contributions	17	3	6	3	3	1	2	—
Actuarial losses (gains)	4	(3)	4	1	3	—	3	1
Transfers	—	2	(1)	—	(1)	1	—	—
Plan amendments	(28)	(5)	(3)	(1)	(2)	(2)	(2)	(9)
Benefits paid	(86)	(18)	(34)	(17)	(17)	(3)	(11)	(1)
Accumulated post-retirement benefit obligation at measurement date	$ 813	$ 189	$ 342	$ 184	$ 156	$ 30	$ 78	$ 32

Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 244	$ 137	$ 1	$ —	$ —	$ 7	$ 22	$ 29
Actual return on plan assets	25	15	1	—	—	2	1	3
Benefits paid	(86)	(18)	(34)	(17)	(17)	(3)	(11)	(1)
Employer contributions (reimbursements)	25	(4)	26	14	14	—	(3)	—
Plan participants' contributions	17	3	6	3	3	1	2	—
Plan assets at measurement date	$ 225	$ 133	$ —	$ —	$ —	$ 7	$ 11	$ 31
Funded status of plan	$ (588)	$ (56)	$ (342)	$ (184)	$ (156)	$ (23)	$ (67)	$ (1)

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current post-retirement liability[a]	**$ 8**	**$ —**	**$ 5**	**$ 3**	**$ 2**	**$ 2**	**$ —**	**$ —**
Noncurrent post-retirement liability[b]	**525**	**59**	**298**	**163**	**135**	**19**	**62**	**1**
Total accrued post-retirement liability	**$ 533**	**$ 59**	**$ 303**	**$ 166**	**$ 137**	**$ 21**	**$ 62**	**$ 1**
Regulatory assets	**$ 262**	**$ —**	**$ 262**	**$ 164**	**$ 98**	**$ —**	**$ 41**	**$ —**
Regulatory liabilities	**$ 301**	**$ 38**	**$ 149**	**$ 93**	**$ 56**	**$ 18**	**$ 67**	**$ —**
Accumulated other comprehensive (income) loss								
Deferred income tax expense	**$ 3**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Prior service credit	**(2)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net actuarial gain	**(9)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Net amounts recognized in accumulated other comprehensive income	**$ (8)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	**$ 4**	**$ 2**	**$ 1**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Unrecognized prior service credit	**(19)**	**(5)**	**(7)**	**(1)**	**(6)**	**(1)**	**(1)**	**(2)**

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current post-retirement liability[a]	$ 36	$ —	$ 29	$ 15	$ 14	$ 2	$ —	$ —
Noncurrent post-retirement liability[b]	552	56	313	169	142	21	67	1
Total accrued post-retirement liability	$ 588	$ 56	$ 342	$ 184	$ 156	$ 23	$ 67	$ 1
Regulatory assets	$ 125	$ —	$ 129	$ 80	$ 49	$ —	$ 46	$ (4)
Regulatory liabilities	$ 147	$ 44	$ —	$ —	$ —	$ 16	$ 64	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 4	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(2)	—	—	—	—	—	—	—
Net actuarial gain	(10)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive	$ (8)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

income

Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss (gain)	$ 5	$ 3	$ 1	$ —	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(19)	(5)	(7)	(1)	(6)	(1)	(1)	(2)

(a) Included in Other within Current Liabilities on the Consolidated Balance Sheets.

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

Assumptions Used for Other Post-Retirement Benefits Accounting

The discount rate used to determine the current year other post-retirement benefits obligation and following year's other post-retirement benefits expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected. The average remaining service period of active covered employees is nine years for Duke Energy, eight years for Duke Energy Carolinas, seven years for Duke Energy Florida, Duke Energy Ohio, and Piedmont, and six years for Progress Energy, Duke Energy Progress, and Duke Energy Indiana.

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

	December 31,		
	2018	**2017**	**2016**
Benefit Obligations			
Discount rate	**4.30%**	3.60%	4.10%
Net Periodic Benefit Cost			
Discount rate	**3.60%**	4.10%	4.40%
Expected long-term rate of return on plan assets	**6.50%**	6.50%	6.50%
Assumed tax rate	**35%**	35%	35%

	Piedmont	
	Two Months Ended	Year Ended
	December 31, 2016	October 31, 2016
Benefit Obligations		
Discount rate	4.10%	3.80%
Net Periodic Benefit Cost		
Discount rate	3.80%	4.38%
Expected long-term rate of return on plan assets	6.75%	7.25%

Assumed Health Care Cost Trend Rate

	December 31,	
	2018	2017
Health care cost trend rate assumed for next year	**6.50%**	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75%**	4.75%
Year that rate reaches ultimate trend	**2024**	2024

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
1-Percentage Point Increase								
Effect on total service and interest costs	**$ 1**	**$ —**	**$ 1**	**$ 1**	**$ —**	**$ —**	**$ —**	**$ —**
Effect on post-retirement benefit obligation	**22**	**5**	**9**	**5**	**4**	**1**	**2**	**1**
1-Percentage Point Decrease								
Effect on total service and interest costs	**(1)**	**—**	**(1)**	**(1)**	**—**	**—**	**—**	**—**
Effect on post-retirement benefit obligation	**(20)**	**(5)**	**(8)**	**(5)**	**(4)**	**(1)**	**(2)**	**(1)**

Expected Benefit Payments

	Duke	Duke Energy	Progress	Duke Energy	Duke Energy	Duke Energy	Duke Energy

(in millions)		Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Years ending December 31,									
2019	$	81 $	19 $	30 $	16 $	14 $	3 $	9 $	2
2020		75	18	29	15	13	3	8	2
2021		71	18	28	15	13	3	7	2
2022		68	17	27	14	12	3	7	3
2023		64	16	26	14	12	3	6	3
2024-2028		266	64	109	59	50	11	26	12

PLAN ASSETS

Description and Allocations

Duke Energy Master Retirement Trust

Assets for both the qualified pension and other post-retirement benefits are maintained in the Duke Energy Master Retirement Trust. Qualified pension and other post-retirement assets related to Piedmont were transferred into the Duke Energy Master Retirement Trust during 2017. Approximately 98 percent of the Duke Energy Master Retirement Trust assets were allocated to qualified pension plans and approximately 2 percent were allocated to other post-retirement plans (comprised of 401(h) accounts), as of December 31, 2018, and 2017. The investment objective of the Duke Energy Master Retirement Trust is to invest in a diverse portfolio of assets that is expected to generate positive surplus return over time (i.e. asset growth greater than liability growth) subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants.

As of December 31, 2018, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.85 percent. The expected long-term rate of return was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers, where applicable. The asset allocation targets were set after considering the investment objective and the risk profile. Equity securities are held for their higher expected returns. Debt securities are primarily held to hedge the qualified pension plan liability. Real assets, return seeking fixed income, hedge funds 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.

Effective January 1, 2019, the target asset allocation for the Duke Energy Retirement Master Trust is 58 percent liability hedging assets and 42 percent return-seeking assets. Duke Energy periodically reviews its asset allocation targets, and over time, as the funded status of the benefit plans increase, the level of asset risk relative to plan liabilities may be reduced to better manage Duke Energy's benefit plan liabilities and reduce funded status volatility.

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 $154 million and $195 million at December 31, 2018, and 2017, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2018, and 2017, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2018, 2017 and 2016, 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, 2018, and the actual asset allocations for the Duke Energy Master Retirement Trust.

		Actual Allocation at	
	Target	December 31,	
	Allocation	2018	2017
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%

Other post-retirement assets

Duke Energy's other post-retirement assets are comprised of VEBA trusts and 401(h) accounts held within the Duke Energy Master Retirement Trust. Duke Energy's investment objective is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants.

The following table presents target and actual asset allocations for the VEBA trusts at December 31, 2018.

	Target	Actual Allocation at December 31,	
	Allocation	**2018**	**2017**
U.S. equity securities	32%	**43%**	41%
Non-U.S. equity securities	6%	**8%**	8%
Real estate	2%	**2%**	2%
Debt securities	45%	**40%**	36%
Cash	15%	**7%**	13%
Total	100%	**100%**	100%

Fair Value Measurements

Duke Energy classifies recurring and non-recurring fair value measurements based on the fair value hierarchy as discussed in Note 16.

Valuation methods of the primary fair value measurements disclosed below are as follows:

Investments in equity securities

Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the reporting period. Principal active markets for equity prices include published exchanges such as NASDAQ and NYSE. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. Prices have not been adjusted to reflect after-hours market activity. The majority of investments in equity securities are valued using Level 1 measurements. When the price of an institutional commingled fund is unpublished, it is not categorized in the fair value hierarchy, even though the funds are readily available at the fair value.

Investments in corporate debt securities and U.S. government securities

Most debt investments are valued based on a calculation using interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. Most debt valuations are Level 2 measurements. If the market for a particular fixed-income security is relatively inactive or illiquid, the measurement is Level 3. U.S. Treasury debt is typically Level 2.

Investments in short-term investment funds

Investments in short-term investment funds are valued at the net asset value of units held at year end and are readily redeemable at the measurement date. Investments in short-term investment funds with published prices are valued as Level 1. Investments in short-term investment funds with unpublished prices are valued as Level 2.

Investments in real estate limited partnerships

Investments in real estate limited partnerships are valued by the trustee at each valuation date (monthly). As part of the trustee's valuation process, properties are externally appraised generally on an annual basis, conducted by reputable, independent appraisal firms, and signed by appraisers that are members of the Appraisal Institute, with the professional designation MAI. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three valuation techniques that can be used to value investments in real estate assets: the market, income or cost approach. The appropriateness of each valuation technique depends on the type of asset or business being valued. In addition, the trustee may cause additional appraisals to be performed as warranted by specific asset or market conditions. Property valuations and the salient valuation-sensitive assumptions of each direct investment property are reviewed by the trustee quarterly and values are adjusted if there has been a significant change in circumstances related to the investment property since the last valuation. Value adjustments for interim capital expenditures are only recognized to the extent that the valuation process acknowledges a corresponding increase in fair value. An independent firm is hired to review and approve quarterly direct real estate valuations. Key inputs and assumptions used to determine fair value includes among others, rental revenue and expense amounts and related revenue and expense growth rates, terminal capitalization rates and discount rates. Development investments are valued using cost incurred to date as a primary input until substantive progress is achieved in terms of mitigating construction and leasing risk at which point a discounted cash flow approach is more heavily weighted. Key inputs and assumptions in addition to those noted above used to determine the fair value of development investments include construction costs and the status of construction completion and leasing. Investments in real estate limited partnerships are valued at net asset value of units held at year end and are not readily redeemable at the measurement date. Investments in real estate limited partnerships are not categorized within the fair value hierarchy.

Duke Energy Master Retirement Trust

The following tables provide the fair value measurement amounts for the Duke Energy Master Retirement Trust qualified pension and other post-retirement assets.

	December 31, 2018				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized(b)
Equity securities	$ 2,373	$ 1,751	$ —	$ —	$ 622
Corporate debt securities	4,054	—	4,054	—	—
Short-term investment funds	363	279	84	—	—
Partnership interests	120	—	—	—	120
Hedge funds	226	—	—	—	226
Real estate limited partnerships	144	—	—	—	144
U.S. government securities	961	—	961	—	—
Guaranteed investment contracts	27	—	—	27	—

Governments bonds – foreign	**30**	**—**	**30**	**—**	**—**
Cash	**28**	**28**	**—**	**—**	**—**
Net pending transactions and other investments	**(2)**	**(6)**	**4**	**—**	**—**
Total assets[a]	**$ 8,324**	**$ 2,052**	**$ 5,133**	**$ 27**	**$ 1,112**

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 27 percent, 31 percent, 15 percent, 16 percent, 5 percent, 7 percent, and 4 percent, respectively, of the Duke Energy Master Retirement Trust at December 31, 2018. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments that are measured at fair value using the net asset value per share practical expedient have not been categorized in the fair value hierarchy.

	December 31, 2017				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized[b]**
Equity securities	$ 2,823	$ 1,976	$ —	$ —	$ 847
Corporate debt securities	4,694	—	4,694	—	—
Short-term investment funds	246	192	54	—	—
Partnership interests	137	—	—	—	137
Hedge funds	226	—	—	—	226
Real estate limited partnerships	135	—	—	—	135
U.S. government securities	762	—	762	—	—
Guaranteed investment contracts	28	—	—	28	—
Governments bonds – foreign	38	—	38	—	—
Cash	6	6	—	—	—
Government and commercial mortgage backed securities	2	—	2	—	—

Net pending transactions and other investments	17	15	2	—	—
Total assets(a)	$ 9,114	$ 2,189	$ 5,552	$ 28	$ 1,345

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 27 percent, 30 percent, 15 percent, 15 percent, 5 percent, 8 percent, and 4 percent, respectively, of the Duke Energy Master Retirement Trust and Piedmont's Pension assets at December 31, 2017. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments that are measured at fair value using the net asset value per share practical expedient have not been categorized in the fair value hierarchy.

The following table provides a reconciliation of beginning and ending balances of Duke Energy Master Retirement Trust qualified pension and other post-retirement assets at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3).

(in millions)	**2018**	**2017(a)**
Balance at January 1	**$ 28**	$ 38
Sales	**(1)**	(2)
Total gains and other, net	**—**	1
Transfer of Level 3 assets to other classifications	**—**	(9)
Balance at December 31	**$ 27**	$ 28

(a) Balance at January 1 includes $9 million associated with Piedmont pension assets.

Other post-retirement assets

The following tables provide the fair value measurement amounts for VEBA trust assets.

	December 31, 2018	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	**$ 3**	**$ 3**
Real estate	**1**	**1**
Equity securities	**25**	**25**
Debt securities	**20**	**20**
Total assets	**$ 49**	**$ 49**

	December 31, 2017	
(in millions)	**Total Fair Value**	**Level 2**

Cash and cash equivalents	$ 8	**$ 8**
Real estate	1	**1**
Equity securities	28	**28**
Debt securities	21	**21**
Total assets	$ 58	$ 58

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. 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.

For new and rehired 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. Certain Piedmont employees whose participation in a prior Piedmont defined benefit plan (that was frozen as of December 31, 2017) are eligible for employer transition credit contributions of 3 to 5 percent of eligible pay per period, for each pay period during the three-year period ending December 31, 2020.

The following table includes pretax employer matching contributions made by Duke Energy and expensed by the Subsidiary Registrants.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont[(a)]
Years ended December 31,								
2018	**$ 213**	**$ 68**	**$ 58**	**$ 40**	**$ 19**	**$ 4**	**$ 10**	**$ 12**
2017	179	61	53	37	16	3	9	7
2016	169	57	50	35	15	3	8	

(a) Piedmont's pretax employer matching contributions were $1 million and $7 million during the two months ended December 31, 2016, and for the year ended October 31, 2016, respectively.

Money Purchase Pension Plan

Piedmont sponsored the MPP plan, which is a defined contribution pension plan that allowed employees to direct investments and assume risk of investment returns. Under the MPP plan, Piedmont annually deposited a percentage of each participant's pay into an account of the MPP plan. This contribution equaled 4 percent of the participant's eligible compensation plus an additional 4 percent of eligible compensation above the Social Security wage base up to the IRS compensation limit. The participant was vested in MPP plan after three years of service. No contributions were made to the MPP plan during the two months ended December 31, 2016. Piedmont contributed $2 million to the MPP plan during each of the years ended December 31, 2017, and October 31, 2016. Effective December 31, 2017, the MPP Plan was merged into the Retirement Savings Plan and the money purchase plan formula was discontinued. Beginning with the 2018 plan year, the former MPP Plan participants are eligible to receive the additional employer contribution under the Retirement Savings Plan, discussed above.

23. INCOME TAXES

Tax Act

On December 22, 2017, President Trump signed the Tax Act into law. Among other provisions, the Tax Act lowered the corporate federal income tax rate from 35 to 21 percent, limits interest deductions outside of regulated utility operations, requires the normalization of excess deferred taxes associated with property under the average rate assumption method as a prerequisite to qualifying for accelerated depreciation and repealed the federal manufacturing deduction. The Tax Act also repealed the corporate AMT and stipulates a refund of 50 percent of remaining AMT credit carryforwards (to the extent the credits exceed regular tax for the year) for tax years 2018, 2019 and 2020 with all remaining AMT credits to be refunded in tax year 2021.

On December 22, 2017, the SEC staff issued SAB 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provides guidance on accounting for the Tax Act's impact. SAB 118 provides a measurement period, which in no case should extend beyond one year from the Tax Act enactment date, during which a company acting in good faith may complete the accounting for the impacts of the Tax Act under ASC Topic 740. In accordance with SAB 118, a company must reflect the income tax effects of the Tax Act in the reporting period in which the accounting under ASC Topic 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements in the first reporting period in which a reasonable estimate can be determined.

As of December 31, 2018, the accounting for the effects of the Tax Act is complete. During the year ended December 31, 2018, Duke Energy recorded the following measurement period adjustments in accordance with SAB 118:

- Additional tax expense of $23 million related to the completion of the analysis of Duke Energy's existing regulatory liability related to deferred taxes;
- A $10 million tax benefit for the remeasurement of deferred tax assets and deferred tax liabilities primarily related to the guidance on bonus depreciation issued by the IRS in August 2018 affecting the computation of the Company's 2017 Federal income tax liability;
- Additional tax expense of $7 million related to the portion of the deferred tax asset as of December 31, 2017, that represents nondeductible long-term incentives under the Tax Act's limitation on the deductibility of executive compensation; and
- During the fourth quarter of 2018, the Company released the $76 million valuation allowance that it recorded in the first quarter of 2018 as a result of additional guidance published by the IRS that stated refundable AMT credits would not be subject to sequestration.
- The majority of Duke Energy's operations are regulated and it is expected that the Subsidiary Registrants will ultimately pass on the savings associated with the amount representing the remeasurement of deferred tax balances related to regulated operations to customers. For Duke Energy's regulated operations, where the reduction is expected to be returned to customers in future rates, the remeasurement has been deferred as a regulatory liability. During 2018, Duke Energy recorded an additional regulatory liability of $83 million, representing the revaluation of those deferred tax balances. The Subsidiary Registrants continue to respond to requests from regulators in various jurisdictions to determine the timing and magnitude of savings they will pass on to customers.

In addition, during 2018 Duke Energy reclassified $573 million of AMT credit carryforwards from noncurrent deferred tax liabilities to a current federal income tax receivable as the Company expects to receive this amount via a refund from the IRS in 2019, based on the expected filing of Duke Energy's 2018 income tax return in the second quarter of 2019.

Income Tax Expense

Components of Income Tax Expense

	Year Ended December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current income taxes								
Federal	**$ (647)**	**$ (8)**	**$ (135)**	**$ (71)**	**$ (49)**	**$ 20**	**$ 29**	**$ 67**
State	**(11)**	**6**	**(5)**	**(5)**	**(10)**	**(1)**	**3**	**1**
Foreign	**3**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total current income taxes	**(655)**	**(2)**	**(140)**	**(76)**	**(59)**	**19**	**32**	**68**
Deferred income taxes								
Federal	**1,064**	**299**	**341**	**256**	**115**	**21**	**74**	**(36)**
State	**49**	**11**	**20**	**(17)**	**45**	**3**	**22**	**5**
Total deferred income taxes(a)(b)	**1,113**	**310**	**361**	**239**	**160**	**24**	**96**	**(31)**
Investment tax credit amortization	**(10)**	**(5)**	**(3)**	**(3)**	**—**	**—**	**—**	**—**
Income tax expense from continuing operations	**448**	**303**	**218**	**160**	**101**	**43**	**128**	**37**
Tax benefit from discontinued operations	**(26)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total income tax expense included in Consolidated Statements of Operations	**$ 422**	**$ 303**	**$ 218**	**$ 160**	**$ 101**	**$ 43**	**$ 128**	**$ 37**

(a) Includes benefits of NOL carryforwards and tax credit carryforwards of $22 million at Duke Energy Carolinas, $293 million at Progress Energy, $59 million at Duke Energy Progress, $219 million at Duke Energy Florida, $17 million at Duke Energy Ohio, $21 million at Duke Energy Indiana and $39 million at Piedmont. In addition, total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $18 million at Duke Energy.

(b) For the year ended December 31, 2018, the Company has revised the December 31, 2017, estimates of the income tax effects of the Tax Act, in accordance with SAB 118. See the Statutory Rate Reconciliation section below for additional information on the Tax Act's impact on income tax expense.

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current income taxes								
Federal	$ (247)	$ 221	$ (436)	$ (95)	$ (188)	$ (37)	$ 128	$ (90)
State	4	20	(5)	2	(11)	2	21	(3)
Foreign	3	—	—	—	—	—	—	—
Total current income taxes	(240)	241	(441)	(93)	(199)	(35)	149	(93)
Deferred income taxes								
Federal	1,344	381	664	378	194	99	138	147
State	102	35	44	10	51	(4)	14	8

Total deferred income taxes[(a)(b)]	1,446	416	708	388	245	95	152	155
Investment tax credit amortization	(10)	(5)	(3)	(3)	—	(1)	—	—
Income tax expense from continuing operations	1,196	652	264	292	46	59	301	62
Tax benefit from discontinued operations	(6)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,190	$ 652	$ 264	$ 292	$ 46	$ 59	$ 301	$ 62

(a) Includes utilization of NOL carryforwards and tax credit carryforwards of $428 million at Duke Energy, $74 million at Progress Energy, $36 million at Duke Energy Florida, $17 million at Duke Energy Ohio, $42 million at Duke Energy Indiana and $79 million at Piedmont. In addition, total deferred income taxes includes benefits of NOL carryforwards and tax credit carryforwards of $10 million at Duke Energy Carolinas and $1 million at Duke Energy Progress.

(b) As a result of the Tax Act, Duke Energy's deferred tax assets and liabilities were revalued as of December 31, 2017. See the Statutory Rate Reconciliation section below for additional information on the Tax Act's impact on income tax expense.

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Current income taxes							
Federal	$ —	$ 139	$ 15	$ (59)	$ 76	$ (7)	$ 7
State	(15)	25	(19)	(25)	22	(13)	6
Foreign	2	—	—	—	—	—	—
Total current income taxes	(13)	164	(4)	(84)	98	(20)	13
Deferred income taxes							
Federal	1,064	430	486	350	199	88	202
State	117	45	50	40	25	11	11
Total deferred income taxes[(a)]	1,181	475	536	390	224	99	213
Investment tax credit amortization	(12)	(5)	(5)	(5)	—	(1)	(1)
Income tax expense from continuing operations	1,156	634	527	301	322	78	225

Tax (benefit) expense from discontinued operations	(30)	—	1	—	—	(36)	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,126	$ 634	$ 528	$ 301	$ 322	$ 42	$ 225

(a) Includes benefits of NOL carryforwards and utilization of NOL and tax credit carryforwards of $648 million at Duke Energy, $4 million at Duke Energy Carolinas, $190 million at Progress Energy, $60 million at Duke Energy Progress, $49 million at Duke Energy Florida, $26 million at Duke Energy Ohio and $58 million at Duke Energy Indiana.

	Piedmont	
(in millions)	**Two Months Ended December 31, 2016**	**Year Ended October 31, 2016**
Current income taxes		
Federal	$ 4	$ 27
State	(2)	12
Total current income taxes	2	39
Deferred income taxes		
Federal	24	79
State	6	6
Total deferred income taxes[a]	30	85
Total income tax expense from continuing operations included in Consolidated Statements of Operations	$ 32	$ 124

(a) Includes benefits of NOL and tax carryforwards of $17 million and $91 million for the two months ended December 31, 2016, and the year ended October 31, 2016, respectively.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Domestic[a]	**$ 3,018**	$ 4,207	$ 3,689
Foreign	**55**	59	45
Income from continuing operations before income taxes	**$ 3,073**	$ 4,266	$ 3,734

(a) Includes a $16 million expense in 2017 related to the Tax Act impact on equity earnings included within Equity in earnings (losses) of unconsolidated affiliates on the Consolidated Statement of Operations.

Taxes on Foreign Earnings

In February 2016, Duke Energy announced it had initiated a process to divest the International Disposal Group and, accordingly, no longer intended to indefinitely reinvest post-2014 undistributed foreign earnings. This change in the company's intent, combined with the extension of bonus depreciation by Congress in late 2015, allowed Duke Energy to more efficiently utilize foreign tax credits and reduce U.S. deferred tax liabilities associated with the historical unremitted foreign earnings by approximately $95 million during the year ended December 31, 2016.

Due to the classification of the International Disposal Group as discontinued operations beginning in the fourth quarter of 2016, income tax amounts related to the International Disposal Group's foreign earnings are presented within Income (Loss) 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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Income tax expense, computed at the statutory rate of 21 percent	$ 645	$ 288	$ 263	$ 174	$ 137	$ 46	$ 109	$ 35
State income tax, net of federal income tax effect	30	14	13	(17)	28	2	20	4
Amortization of excess deferred income tax	(61)	—	(55)	(1)	(54)	(3)	(2)	—
AFUDC equity income	(42)	(15)	(22)	(12)	(10)	(2)	(2)	—
AFUDC equity depreciation	31	18	9	5	4	1	4	—
Renewable energy production tax credits	(129)	—	—	—	—	—	—	—
Other tax credits	(28)	(7)	(13)	(5)	(8)	(1)	(1)	(3)
Tax Act(a)	20	1	25	19	—	2	—	—
Other items, net	(18)	4	(2)	(3)	4	(2)	—	1
Income tax expense from continuing operations	$ 448	$ 303	$ 218	$ 160	$ 101	$ 43	$ 128	$ 37
Effective tax rate	14.6%	22.1%	17.4%	19.3%	15.4%	19.6%	24.6%	22.3%

(a) For the year ended December 31, 2018, the Company revised the December 31, 2017 estimates of the income tax effects of the Tax Act, in accordance with SAB 118. Amounts primarily include but are not limited to items that are excluded for ratemaking purposes related certain wholesale fixed rate contracts, remeasurement of nonregulated net deferred tax liabilities, Federal net operating losses, and valuation allowance on foreign tax credits.

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Income tax expense, computed at the statutory rate of 35 percent	$ 1,493	$ 653	$ 536	$ 353	$ 265	$ 88	$ 229	$ 70
State income tax, net of federal income tax effect	69	36	25	8	26	(1)	23	3
AFUDC equity income	(81)	(37)	(32)	(17)	(16)	(4)	(8)	—
Renewable energy production tax credits	(132)	—	—	—	—	—	—	—
Tax Act(a)	(112)	15	(246)	(40)	(226)	(23)	55	(12)
Tax true up	(52)	(24)	(19)	(13)	(7)	(5)	(6)	—
Other items, net	11	9	—	1	4	4	8	1
Income tax expense from continuing operations	$ 1,196	$ 652	$ 264	$ 292	$ 46	$ 59	$ 301	$ 62
Effective tax rate	28.0%	34.9%	17.2%	29.0%	6.1%	23.4%	46.0%	30.8%

(a) Amounts primarily include but are not limited to items that are excluded for ratemaking purposes related to abandoned or impaired assets, certain wholesale fixed rate contracts, remeasurement of nonregulated net deferred tax liabilities, Federal net operating losses, and valuation allowance on foreign tax credits.

	Year Ended December 31, 2016						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Income tax expense, computed at the statutory rate of 35 percent	$ 1,307	$ 630	$ 548	$ 315	$ 306	$ 95	$ 212
State income tax, net of federal income tax effect	64	46	20	10	30	(2)	11
AFUDC equity income	(70)	(36)	(26)	(17)	(9)	(2)	(6)
Renewable energy production tax credits	(97)	—	—	—	—	—	—
Audit adjustment	5	3	—	—	—	—	—
Tax true up	(14)	(14)	(11)	(3)	(9)	(16)	2
Other items, net	(39)	5	(4)	(4)	4	3	6
Income tax expense from continuing operations	$ 1,156	$ 634	$ 527	$ 301	$ 322	$ 78	$ 225
Effective tax rate	31.0%	35.2%	33.7%	33.4%	36.9%	28.9%	37.1%

	Piedmont	
(in millions)	Two Months Ended December 31, 2016	Year Ended October 31, 2016
Income tax expense, computed at the statutory rate of 35 percent	$ 30	$ 111

State income tax, net of federal income tax effect	1	11
Other items, net	1	2
Income tax expense from continuing operations	$ 32	$ 124
Effective tax rate	37.2%	39.1%

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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Deferred credits and other liabilities	$ 164	$ 64	$ 35	$ 53	$ —	$ 17	$ 6	$ 17
Capital lease obligations	60	26	—	—	—	—	2	—
Pension, post-retirement and other employee benefits	347	24	110	47	58	16	24	(1)
Progress Energy merger purchase accounting	483	—	—	—	—	—	—	—

adjustments[a]								
Tax credits and NOL carryforwards	**4,580**	**257**	**693**	**215**	**363**	**42**	**237**	**110**
Regulatory liabilities and deferred credits	**—**	**—**	**—**	**—**	**—**	**56**	**—**	**48**
Investments and other assets	**—**	**—**	**—**	**—**	**—**	**18**	**—**	**16**
Other	**25**	**6**	**5**	**5**	**—**	**1**	**(1)**	**—**
Valuation allowance	**(484)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total deferred income tax assets	**5,175**	**377**	**843**	**320**	**421**	**150**	**268**	**190**
Investments and other assets	**(1,317)**	**(795)**	**(430)**	**(272)**	**(163)**	**—**	**(5)**	**—**
Accelerated depreciation rates	**(10,124)**	**(3,207)**	**(3,369)**	**(1,735)**	**(1,670)**	**(967)**	**(1,081)**	**(733)**
Regulatory assets and deferred debits, net	**(1,540)**	**(64)**	**(985)**	**(432)**	**(574)**	**—**	**(191)**	**—**
Other	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(8)**
Total deferred income tax liabilities	**(12,981)**	**(4,066)**	**(4,784)**	**(2,439)**	**(2,407)**	**(967)**	**(1,277)**	**(741)**
Net deferred income tax liabilities	**$ (7,806)**	**$ (3,689)**	**$ (3,941)**	**$ (2,119)**	**$ (1,986)**	**$ (817)**	**$ (1,009)**	**$ (551)**

(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, 2018	
(in millions)	**Amount**	**Expiration Year**
Investment tax credits	**$ 1,614**	2024 — 2038
Alternative minimum tax credits	**574**	Refundable by 2021
Federal NOL carryforwards[a][e]	**788**	2022 — Indefinite
State NOL carryforwards and credits[b][e]	**301**	2019 — Indefinite
Foreign NOL carryforwards[c]	**12**	2027 — 2037
Foreign Tax Credits[d]	**1,271**	2024 — 2027
Charitable contribution carryforwards	**20**	2019 — 2023
Total tax credits and NOL carryforwards	**$ 4,580**	

(a) A valuation allowance of $4 million has been recorded on the Federal NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.
(b) A valuation allowance of $85 million has been recorded on the state NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.
(c) 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.
(d) A valuation allowance of $383 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.
(e) Indefinite carryforward for Federal NOLs, and NOLs for states that have adopted the Tax Act's NOL provisions, generated in tax years beginning after December 31, 2017.

	December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Deferred credits and other liabilities	$ 143	$ 33	$ 78	$ 23	$ 49	$ 11	$ 6	$ (5)
Capital lease obligations	49	14	—	—	—	—	2	—
Pension, post-retirement and other employee								

benefits	295	(17)	111	44	60	14	18	(4)
Progress Energy merger purchase accounting adjustments[(a)]	536	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,527	234	402	156	143	25	216	70
Regulatory liabilities and deferred credits	—	222	—	—	—	65	—	61
Investments and other assets	—	—	—	—	—	—	1	18
Other	73	10	1	4	—	—	—	—
Valuation allowance	(519)	—	(14)	—	—	—	—	—
Total deferred income tax assets	5,104	496	578	227	252	115	243	140
Investments and other assets	(1,419)	(849)	(470)	(289)	(187)	—	(14)	—
Accelerated depreciation rates	(9,216)	(3,060)	(2,803)	(1,583)	(1,257)	(896)	(966)	(697)
Regulatory assets and deferred debits, net	(1,090)	—	(807)	(238)	(569)	—	(188)	—
Other	—	—	—	—	—	—	—	(7)
Total deferred income tax liabilities	(11,725)	(3,909)	(4,080)	(2,110)	(2,013)	(896)	(1,168)	(704)
Net deferred income tax liabilities	$ (6,621)$	(3,413)$	(3,502)$	(1,883)$	(1,761)$	(781)$	(925)$	(564)

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

On June 28, 2017, the North Carolina General Assembly amended N.C. Gen. Stat. 105-130.3, reducing the North Carolina corporate income tax rate from a statutory rate of 3.0 to 2.5 percent beginning January 1, 2019. Duke Energy recorded a net reduction of approximately $55 million to their North Carolina deferred tax liabilities in the second quarter of 2017. The significant majority of this deferred tax liability reduction was offset by recording a regulatory liability pending NCUC determination of the disposition of amounts related to Duke Energy Carolinas, Duke Energy Progress and Piedmont. The impact did not have a significant impact on the financial position, results of operation or cash flows of Duke Energy, Duke Energy Carolinas, Progress Energy or Duke Energy Progress.

UNRECOGNIZED TAX BENEFITS

The following tables present changes to unrecognized tax benefits.

	Year Ended December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Unrecognized tax benefits – January 1	**$ 25**	**$ 5**	**$ 5**	**$ 5**	**$ 5**	**$ 1**	**$ 1**	**$ 3**
Unrecognized tax benefits increases (decreases)								
Gross decreases – tax positions in prior periods	**(2)**	**(1)**	**—**	**—**	**(4)**	**—**	**—**	**—**
Gross increases – current period tax positions	**7**	**2**	**4**	**1**	**2**	**—**	**—**	**1**
Decreases due to settlements	**(6)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Total changes	**(1)**	**1**	**4**	**1**	**(2)**	**—**	**—**	**1**
Unrecognized tax benefits – December 31	**$ 24**	**$ 6**	**$ 9**	**$ 6**	**$ 3**	**$ 1**	**$ 1**	**$ 4**

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Unrecognized tax benefits – January 1	$ 17	$ 1	$ 2	$ 2	$ 4	$ 4	$ —	$ —
Unrecognized tax benefits increases (decreases)								
Gross increases – tax positions in prior periods	12	4	3	3	1	1	1	3
Gross decreases – tax positions in prior periods	(4)	—	—	—	—	(4)	—	—
Total changes	8	4	3	3	1	(3)	1	3
Unrecognized tax benefits – December 31	$ 25	$ 5	$ 5	$ 5	$ 5	$ 1	$ 1	$ 3

	Year Ended December 31, 2016						
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**
Unrecognized tax benefits – January 1	$ 88	$ 72	$ 1	$ 3	$ —	$ —	$ 1
Unrecognized tax benefits increases (decreases)							
Gross increases – tax positions in prior periods	—	—	—	—	4	4	—
Gross decreases – tax positions in prior periods	(4)	(4)	(1)	(1)	—	—	—
Decreases due to settlements	(68)	(67)	—	—	—	—	(1)
Reduction due to lapse of statute of limitations	1	—	2	—	—	—	—
Total changes	(71)	(71)	1	(1)	4	4	(1)
Unrecognized tax benefits – December 31	$ 17	$ 1	$ 2	$ 2	$ 4	$ 4	$ —

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2018. All Duke Energy Registrants do not anticipate a material increase or decrease in unrecognized tax benefits within the next 12 months.

	December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Amount that if recognized, would affect the effective tax rate or regulatory liability(a)	**$ 21**	**$ 6**	**$ 9**	**$ 6**	**$ 3**	**$ 1**	**$ 1**	**$ 4**
Amount that if recognized, would be recorded as a component of discontinued operations	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

(a) Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont are unable to estimate the specific amounts that would affect the effective tax rate versus the regulatory liability.

OTHER TAX MATTERS

The following tables include interest recognized in the Consolidated Statements of Operations and the Consolidated Balance Sheets.

	Year Ended December 31, 2018		
(in millions)	Duke Energy	Progress Energy	Duke Energy Progress
Net interest income recognized related to income taxes	$ 2	$ —	$ —
Interest payable related to income taxes	3	1	1

	Year Ended December 31, 2017				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Net interest income recognized related to income taxes	$ —	$ —	$ 1	$ —	$ 1
Net interest expense recognized related to income taxes	—	2	—	—	—
Interest payable related to income taxes	5	25	1	1	—

	Year Ended December 31, 2016				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Net interest income recognized related to income taxes	$ —	$ —	$ 1	$ —	$ 2
Net interest expense recognized related to income taxes	—	7	—	—	—
Interest payable related to income taxes	4	23	1	1	—

Piedmont recognized $1 million in net interest income related to income taxes in the Consolidated Statements of Operations for the year ended October 31, 2016.

Duke Energy and its subsidiaries are no longer subject to U.S. federal examination for years before 2015. With few exceptions, Duke Energy and its subsidiaries are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2015.

24. 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, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Interest income	$ 20	$ 1	$ 18	$ 1	$ 18	$ 7	$ 9	$ 1
AFUDC equity	221	73	104	57	47	11	32	—
Post in-service equity returns	15	9	5	5	—	1	—	—
Nonoperating income, other	143	70	38	24	21	4	4	13

Other income and expense, net	**$ 399**	**$ 153**	**$ 165**	**$ 87**	**$ 86**	**$ 23**	**$ 45**	**$ 14**

	Year Ended December 31, 2017							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Interest income	$ 13	$ 2	$ 6	$ 2	$ 5	$ 6	$ 8	$ —
AFUDC equity	237	106	92	47	45	11	28	—
Post in-service equity returns	40	28	12	12	—	—	—	—
Nonoperating income, other	218	63	99	54	46	6	11	(11)
Other income and expense, net	$ 508	$ 199	$ 209	$ 115	$ 96	$ 23	$ 47	$ (11)

	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, other	175	53	94	67	35	—	4
Other income and expense, net[(a)]	$ 463	$ 214	$ 186	$ 132	$ 63	$ 11	$ 26

(a) Amounts for Piedmont for the two months ended December 31, 2016, and for the year ended October 31, 2016, were not material.

25. SUBSEQUENT EVENTS

For information on subsequent events related to the adoption of the new lease accounting standard, regulatory matters, commitments and contingencies and debt and credit facilities, see Notes 1, 4, 5 and 6, respectively.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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				

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		(206,646)	(206,646)	[redacted]	[redacted]
2		25,837	25,837	[redacted]	[redacted]
3				[redacted]	[redacted]
4		25,837	25,837	715,397,849	715,423,686
5		(180,809)	(180,809)	[redacted]	[redacted]
6		(180,809)	(180,809)	[redacted]	[redacted]
7		31,539	31,539	[redacted]	[redacted]
8				[redacted]	[redacted]
9		31,539	31,539	667,036,191	667,067,730
10		(149,270)	(149,270)	[redacted]	[redacted]

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	23,190,027,326	23,190,027,326
4	Property Under Capital Leases	136,522,508	136,522,508
5	Plant Purchased or Sold		
6	Completed Construction not Classified	5,574,455,792	5,574,455,792
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	28,901,005,626	28,901,005,626
9	Leased to Others		
10	Held for Future Use	36,972,974	36,972,974
11	Construction Work in Progress	1,665,669,162	1,665,669,162
12	Acquisition Adjustments	349,801,941	349,801,941
13	Total Utility Plant (8 thru 12)	30,953,449,703	30,953,449,703
14	Accum Prov for Depr, Amort, & Depl	12,297,905,722	12,297,905,722
15	Net Utility Plant (13 less 14)	18,655,543,981	18,655,543,981
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	11,931,482,059	11,931,482,059
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	322,831,324	322,831,324
22	Total In Service (18 thru 21)	12,254,313,383	12,254,313,383
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	43,592,339	43,592,339
33	Total Accum Prov (equals 14) (22,26,30,31,32)	12,297,905,722	12,297,905,722

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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	25,410,963	38,152,118
3	Nuclear Materials	330,444,441	128,805,406
4	Allowance for Funds Used during Construction	17,019,785	8,878,054
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	372,875,189	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		223,584,082
9	In Reactor (120.3)	842,377,497	223,584,082
10	SUBTOTAL (Total 8 & 9)	842,377,497	
11	Spent Nuclear Fuel (120.4)	344,303,937	246,450,291
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	830,851,022	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	728,705,601	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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
	39,168,503	24,394,578	2
	174,399,623	284,850,224	3
	10,015,955	15,881,884	4
			5
		325,126,686	6
			7
	223,584,082		8
	246,450,291	819,511,288	9
		819,511,288	10
	173,259,241	417,494,987	11
			12
-185,854,030	156,486,343	860,218,709	13
		701,914,252	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 $173,259,242 of nuclear fuel assemblies retired from the reactor and ($16,772,899) of dry cask storage expenditures.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	54,243,304	5,628,149
4	(303) Miscellaneous Intangible Plant	443,609,602	23,173,255
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	498,613,300	28,801,404
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	27,793,419	4,867,013
9	(311) Structures and Improvements	504,022,409	27,629,890
10	(312) Boiler Plant Equipment	2,601,972,910	177,059,119
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	368,349,154	9,802,548
13	(315) Accessory Electric Equipment	248,856,308	10,054,968
14	(316) Misc. Power Plant Equipment	66,878,908	673,758
15	(317) Asset Retirement Costs for Steam Production	732,176,235	183,873,880
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,550,049,343	413,961,176
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	68,358,438	
19	(321) Structures and Improvements	3,050,429,039	48,225,824
20	(322) Reactor Plant Equipment	2,502,360,280	87,779,102
21	(323) Turbogenerator Units	1,075,262,924	338,747,991
22	(324) Accessory Electric Equipment	1,086,356,693	143,796,361
23	(325) Misc. Power Plant Equipment	627,336,381	27,558,766
24	(326) Asset Retirement Costs for Nuclear Production	876,137,782	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	9,286,241,537	646,108,044
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	2,828,917	
28	(331) Structures and Improvements	14,112,092	4,316,084
29	(332) Reservoirs, Dams, and Waterways	51,078,706	2,725,151
30	(333) Water Wheels, Turbines, and Generators	37,737,022	1,037,227
31	(334) Accessory Electric Equipment	26,997,643	851,046
32	(335) Misc. Power PLant Equipment	4,330,408	696,615
33	(336) Roads, Railroads, and Bridges	21,205	
34	(337) Asset Retirement Costs for Hydraulic Production	536,917	1,197,201
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	137,642,910	10,823,324
36	D. Other Production Plant		
37	(340) Land and Land Rights	10,002,051	
38	(341) Structures and Improvements	307,743,688	3,147,864
39	(342) Fuel Holders, Products, and Accessories	122,038,401	8,000,999
40	(343) Prime Movers	1,959,320,793	110,448,900
41	(344) Generators	466,397,940	13,017,410
42	(345) Accessory Electric Equipment	316,158,209	1,907,038
43	(346) Misc. Power Plant Equipment	50,884,711	1,715,624
44	(347) Asset Retirement Costs for Other Production	15,015,891	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,247,561,684	138,237,835
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	17,221,495,474	1,209,130,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	184,440,302	6,608,276
49	(352) Structures and Improvements	107,581,092	4,623,862
50	(353) Station Equipment	1,010,690,620	74,700,978
51	(354) Towers and Fixtures	65,706,391	13,364,706
52	(355) Poles and Fixtures	699,884,184	46,665,226
53	(356) Overhead Conductors and Devices	529,338,568	25,786,119
54	(357) Underground Conduit	23,999	9,101
55	(358) Underground Conductors and Devices	21,603,999	
56	(359) Roads and Trails	312,523	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,619,581,678	171,758,268
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	74,831,388	597,698
61	(361) Structures and Improvements	113,850,110	12,918,922
62	(362) Station Equipment	634,905,139	47,810,911
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	756,893,557	103,953,712
65	(365) Overhead Conductors and Devices	1,103,550,463	111,377,491
66	(366) Underground Conduit	193,000,619	7,383,369
67	(367) Underground Conductors and Devices	1,075,777,170	61,807,393
68	(368) Line Transformers	1,037,932,053	97,484,597
69	(369) Services	488,412,861	21,606,829
70	(370) Meters	220,138,035	82,436,356
71	(371) Installations on Customer Premises	292,262,452	27,639,911
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	244,647,875	21,128,346
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,236,201,722	596,145,535
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	8,135,565	48,466
87	(390) Structures and Improvements	167,716,928	1,428,609
88	(391) Office Furniture and Equipment	65,082,718	31,563,127
89	(392) Transportation Equipment	77,451,435	1,842,278
90	(393) Stores Equipment	2,747,010	150,862
91	(394) Tools, Shop and Garage Equipment	76,320,679	15,822,445
92	(395) Laboratory Equipment	6,780,357	
93	(396) Power Operated Equipment	6,319,232	235,853
94	(397) Communication Equipment	227,613,170	30,320,782
95	(398) Miscellaneous Equipment	27,123,427	663,837
96	SUBTOTAL (Enter Total of lines 86 thru 95)	665,290,521	82,076,259
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)	668,008,109	82,076,259
100	TOTAL (Accounts 101 and 106)	27,243,900,283	2,087,911,845
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)	27,243,900,283	2,087,911,845

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
43,157			717,237		2
			59,871,453		3
1,157			466,781,700		4
44,314			527,370,390		5
					6
					7
-3,293			32,663,725		8
2,385,220	153,590	-188,625	529,232,044		9
40,184,609	10,239,409		2,749,086,829		10
					11
2,100,659			376,051,043		12
1,789,940		-228,691	256,892,645		13
716,592		1,098,629	67,934,703		14
88,853,026			827,197,089		15
136,026,753	10,392,999	681,313	4,839,058,078		16
					17
			68,358,438		18
11,735,654	-33,067		3,086,886,142		19
27,638,866			2,562,500,516		20
87,111,870			1,326,899,045		21
15,481,855		-10,225	1,214,660,974		22
2,520,205		-509,173	651,865,769		23
			876,137,782		24
144,488,450	-33,067	-519,398	9,787,308,666		25
					26
			2,828,917		27
60,337		127,792	18,495,631		28
117,318			53,686,539		29
698,131			38,076,118		30
2,029,235			25,819,454		31
15,650			5,011,373		32
			21,205		33
			1,734,118		34
2,920,671		127,792	145,673,355		35
					36
			10,002,051		37
861,750	-2,528,622	11,635,626	319,136,806		38
7,516,553	18,881	1,399,364	123,941,092		39
106,057,037	572,564	-24,819,892	1,939,465,328		40
5,959,001	5,469	1,287,644	474,749,462		41
2,197,118	35,426	8,241,596	324,145,151		42
727,119	6,937	-549,458	51,330,695		43
	-7,373,456		7,642,435		44
123,318,578	-9,262,801	-2,805,120	3,250,413,020		45
406,754,452	1,097,131	-2,515,413	18,022,453,119		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
211,959		-20,584	190,816,035		48
679,597	-184,038	-2,812,542	108,528,777		49
6,217,149		-8,999,617	1,070,174,832		50
44,350		-90,383	78,936,364		51
1,083,452		-2,185,717	743,280,241		52
2,202,133		-1,883,165	551,039,389		53
814			32,286		54
			21,603,999		55
			312,523		56
					57
10,439,454	-184,038	-15,992,008	2,764,724,446		58
					59
-45,756		20,584	75,495,426		60
1,213,502		1,523,628	127,079,158		61
5,496,681		5,836,017	683,055,386		62
					63
3,927,921		-1,133,917	855,785,431		64
6,174,462		-330,033	1,208,423,459		65
604,921			199,779,067		66
2,949,392			1,134,635,171		67
4,161,733		-594	1,131,254,323		68
-171,755,490			681,775,180		69
38,456,931			264,117,460		70
1,350,715			318,551,648		71
					72
963,788			264,812,433		73
					74
-106,501,200		5,915,685	6,944,764,142		75
					76
					77
					78
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					83
					84
					85
35,943			8,148,088		86
3,512,601	-116,015	1,288,914	166,805,835		87
10,483,591		144,801	86,307,055		88
9,716,658		398,762	69,975,817		89
781,974		-55,965	2,059,933		90
6,315,233		4,419,769	90,247,660		91
146,326		105,757	6,739,788		92
532,601		-342,797	5,679,687		93
84,157,608		6,195,476	179,971,820		94
5,184,025		437,019	23,040,258		95
120,866,560	-116,015	12,591,736	638,975,941		96
					97
			2,717,588		98
120,866,560	-116,015	12,591,736	641,693,529		99
431,603,580	797,078		28,901,005,626		100
					101
					102
					103
431,603,580	797,078		28,901,005,626		104

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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					
5					
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40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	CAPE FEAR - SILVER CITY 230KV LINE - CHATHAM COUNTY	11/2009	2023	3,080,978
3	CAPE FEAR - SILVER CITY 230KV LINE - LEE COUNTY	11/2009	2023	1,375,369
4	FLORENCE - MARION 230KV LINE - DILLON COUNTY	11/2009	2023	381,007
5	FLORENCE - MARION 230KV LINE - FLORENCE COUNTY	11/2009	2023	2,178,967
6	FLORENCE - MARION 230KV LINE - MARION COUNTY	11/2009	2023	440,593
7	FUQUAY BROAT STREET 115KV LINE - WAKE COUNTY	2/2017	2025	1,968,531
8	GARNER EAST 230KV SUBSTATION - WAKE COUNTY	05/2011	2023	3,610,841
9	MAYO FOSSIL - ASH POND - PERSON COUNTY	3/1983	2020	1,458,908
10	MCDOWELL STREET SUBSTATION - BUNCOMBE COUNTY	6/2016	2020	2,305,226
11	WEATHERSPOON IC - FUTURE GENERATION ADDITION	7/2008	2019	633,646
12	HARLOWE 230KV SUBSTATION - CARTERET COUNTY	5/2016	2020	321,135
13	ASHEVILLE FLAT CREEK 115KV SUBSTATION	2/2017	2020	963,966
14	KENLY 115KV SUBSTATION - JOHNSTON COUNTY	6/2011	2025	416,389
15	CARVER STREET SUBSTATION - BUNCOMBE COUNTY	4/2018	2020	5,301,322
16	VOLVO DEALERSHIP FUTURE USE - COUNTY BUNCOMBE	9/2017	2020	16,444,917
17	GRANTS CREEK 230KV SUBSTATION - ONSLOW COUNTY	8/2016	2020	1,344,706
18	ASHEVILLE PATTON SUBSTATION	10/2018	2019	1,266,267
19	CHATHAM PARK SUBSTATION - CHATHAM COUNTY	11/2016	2021	1,043,619
20	HARLOWE 230 KV SWITCHING STATION - CRAVEN COUNTY	9/2017	2020	752,018
21	Other Property:			
22	GREEN LEVEL 115KV - WAKE COUNTY	8/2018	2019	-9,309,625
23	Other Land and Rights < $250K (31 Items)			994,194
24				
25				
26				
27				
28				
29				
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46				
47	Total			36,972,974

Schedule Page: 214 Line No.: 22 Column: d

The -$9.3m Green Level 115k T4603 in Wake County (Project 170907A01. Functional Class: Electric - Distribution Plant) represents an adjustment made to a land purchase transaction that offsets to the FERC Form 1 p.216 Construction Work in Progress – Electric (Line 4b). An adjustment will be made to these accounts in January 2019.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION PLANT	
2		
3	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NORTH CAROLINA	24,240,442
4	GREEN LEVEL WEST- ACQUIRE LAND FOR SUBSTATION	10,538,593
5	HOPE MILLS - CONSTRUCT BANK #2	7,069,913
6	WILMINGTON SUNSET PARK SUBSTATION	5,384,600
7	ENVIVA PELLETS HAMLET LLC SITE	4,951,367
8	CEDAR ISLAND POD	3,891,651
9	BEARD SUBSTATION - CONVERT EASTOVER	3,346,040
10	FURQUAY WADE NASH SUBSTATION	3,078,750
11	DOWNTOWN RALEIGH DISTRIBUTION AUTOMATION	3,000,828
12	DISTRIBUTION LIGHTING INSTALLATION	2,744,349
13	MOUNT OLIVE SUBSTATION	2,487,852
14	SMARTGRID DEP TRANSFORMER RETROFIT	2,152,797
15	SMARTGRID DEP CABLE	2,121,700
16	ANGIER - ADD BANK #2	2,088,829
17	MICAVILLE 3 PHASE REGULATORS	2,081,438
18	WILMINGTON OGDEN CAPACITY PLANNING	2,012,946
19	SCOTTS HILL - ADD 2ND FEEDER BANK	1,892,948
20	FLORENCE MARS BLUFF SUBSTATION	1,891,430
21	DISTRIBUTION OIL BREAKER	1,852,124
22	BUDGET FOR CAPITAL WORK	1,850,628
23	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - SOUTH CAROLINA	1,816,813
24	NORTH BEAUFORT - ACQUIRE LAND FOR SUBSTATION	1,718,900
25	HIGHWAY 87 NORTH - FEEDER RELIEF	1,424,350
26	BEAUFORT - INCREASE CAPACITY	1,259,742
27	REEMS CREEK - SUBSTATION SITE PURCHASE	1,237,537
28	WARRENTON INDUSTRIAL RECONDUCTOR	1,221,451
29	GOLDSBORO LANGSTON - INCREASE CAPACITY	1,014,491
30	SMARTGRID DEP TARGETED OVERHEAD/UNDERGROUND CONVERSION	1,011,121
31	WILMINGTON ELEMENTIS SUBSTATION	1,001,514
32	PROJECTS LESS THAN $1 MILLION	54,946,073
33	TOTAL DISTRIBUTION PLANT $155,331,217	
34		
35	GENERAL PLANT	
36		
37	CARY-LINE & SERVICE BUILDING	13,326,844
38	CENTRAL ABERDEEN CONSOLIDATION	8,738,986
39	CUSTOMER CONNECT FUNDING PROJECT	7,605,587
40	PROGRESS ENERGY CAROLINAS ACCRUAL	6,834,910
41	MICROWAVE PROJECTS - CAROLINAS EAST	4,478,527
42	DEP TOWERS, SHELTERS, & POWER SUPPLIES	2,858,264
43	TOTAL	1,665,669,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SMART GRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	2,067,522
2	PANASONIC UNITS - CAROLINAS EAST	2,057,588
3	DEE SECURE NETWORK INFRASTRUCTURE	1,569,566
4	TELECOM PROJECTS FOR POWER DELIVERY CAROLINA EAST - ELECTRIC	1,516,033
5	DEF GRIDWAN	1,237,153
6	DEF NETWORK ASSETS AND SYSTEM TOOLS	1,200,811
7	DEP GRIDWAN CORE ROUTER UPFIT	1,187,844
8	DEP LAND MOBILE RADIO	1,155,046
9	ESO CONTROL CENTER FACILITIES - CAROLINAS EAST	1,112,033
10	CAROLINAS EAST - PURCHASE CAPITAL TOOLS	1,051,304
11	PROJECTS LESS THAN $1 MILLION	6,748,173
12	TOTAL GENERAL PLANT $64,746,191	
13		
14	INTANGIBLE PLANT	
15		
16	DISTRIBUTED MANAGEMENT SYSTEM PROJECT #3	17,803,495
17	SMART GRID DISTRIBUTED MANAGEMENT SYSTEM CONSOLIDATION - TED THOMAS TOWER	7,827,065
18	CUSTOMER CONNECT FUNDING PROJECT	6,097,828
19	SMART GRID CUSTOMER BILLING (CIM) TO METER DATA MANAGEMENT INTEGRATION	5,385,498
20	SMART GRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	5,369,206
21	SMART GRID TRANSMISSION OUTAGE APPLICATION SOFTWARE	5,263,301
22	SMART GRID DEE TRANSMISSION HEALTH RISK MANAGEMENT	3,334,591
23	DEE ADVANCED METERING INFRASTRUCTURE OPERATIONS CENTER	1,556,549
24	APPLICATION ENHANCEMENTS AND FIXES	1,376,749
25	ARCOS SYSTEM OUTAGE STAFFING PROJECT	1,140,789
26	PROJECTS LESS THAN $1 MILLION	8,507,304
27	TOTAL INTANGIBLE PLANT $63,662,375	
28		
29	PRODUCTION PLANT	
30		
31	ASHEVILLE COMBINED CYCLE	544,100,250
32	ROXBORO FUEL GAS DESULFURIZATION WASTEWATER TREATMENT	104,884,949
33	HARRIS VESSEL HEAD (ALLOY 600)	58,873,720
34	BRUNSWICK UNIT 2 MAIN TURBINE GOVERNOR CONTROL SYSTEM	45,396,297
35	ROXBORO STORM / PROCESS WATER REROUTE	34,697,102
36	MAYO CONSTRUCT NEW LINED RETENTION BASIN	32,824,215
37	MAYO STORM & PROCESS WATER REROUTE	20,764,111
38	BRUNSWICK MELLA PLUS	20,139,576
39	BRUNSWICK UNIT 1 FLEET REFUEL BRIDGE CRANE	16,564,720
40	MAYO FUEL GAS DESULFURIZATION WASTEWATER TREATMENT	13,888,590
41	BRUNSWICK UNIT 2 FEEDWATER HEATER 4&5 VALVE	13,860,043
42	HARRIS RM11 SYSTEM	12,938,696
43	TOTAL	1,665,669,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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 ALT DECAY PRI HEAT	12,035,156
2	BRUNSWICK HSM PURCHASE	11,380,498
3	BRUNSWICK UNIT 2 PPC/ERFIS SOFTWARE	11,281,008
4	BRUNSWICK UNIT 2 FEEDWATER HEATER	10,704,416
5	HARRIS PERIMETER INTRUSION DETECTION	9,837,620
6	SAFETY RELATED BATTERY CHARGERS	8,788,529
7	BRUNSWICK OPEN PHASE FAULT DETECTION	8,350,501
8	HARRIS DRY WET STORAGE	7,612,020
9	BRUNSWICK UNIT 2 REACTOR REFUEL BRIDGE CRANE	7,228,775
10	BRUNSWICK RADIO SYSTEM	6,695,327
11	BRUNSWICK UNIT 1 CW PUMP	6,691,557
12	SECURITY BREACHES AND DEFENSIVE POSITIONS	6,061,561
13	BRUNSWICK SALT WATER PUMP	5,724,491
14	SAFETY RELATED CHILLERS	5,689,024
15	BRUNSWICK EMERGENCY WASTE PROCESSING SKID	5,599,487
16	ROXBORO - LANDFILL LEACHATE PIPING	4,944,895
17	BRUNSWICK WASTE WATER PLANT	4,814,078
18	BRUNSWICK PERIMETER INTRUSION DETECTION	4,592,774
19	BLEWETT FERC INSPECTION FOLLOW-UP ACTIVITIES	4,470,431
20	BRUNSWICK UNIT 1 START UP AUXILIARY TRANSFROMER	4,468,520
21	BRUNSWICK SERVICE WATER PUMP	3,877,835
22	BRUNSWICK UNIT 2 TRAVEL SCREEN INSTRUMENT IMPROVEMENT	3,809,006
23	HARRIS FIRE DETECTION SYSTEM	3,768,706
24	BRUNSWICK UNIT 2 REACTOR BUILDING ROOF DRAIN	3,758,212
25	BRUNSWICK UNIT 1 TRAVEL SCREEN INSTRUMENT IMPROVEMENT	3,646,140
26	HARRIS SPENT FUEL POOL DELTA	3,605,613
27	HARRIS HEATER DRAIN SYSTEM TO DCS	3,559,321
28	ROBINSON PHASE IV DRY STORAGE	3,308,626
29	BRUNSWICK UNIT 1 ASCOM MINI-CELL	3,288,731
30	BLEWETT HYDROELECTRIC FISH PASSAGE	3,197,682
31	HARRIS PLANT PROCESS COMPUTER	2,942,180
32	ROXBORO DRY FLY ASH SYSTEM	2,855,091
33	ROBINSON PLANT PROCESS COMPUTERS	2,821,968
34	BRUNSWICK UNIT 1 FEEDWATER HEATER	2,728,301
35	ROBINSON CONDENSATE POLISHING DCS	2,674,089
36	BRUNSWICK UNIT 2 MOISTURE SEPARATER REHEATER	2,500,539
37	TELECOM NUCLEAR FUNDING PROJECT	2,322,928
38	ROXBORO - NERC CIP	2,322,536
39	BRUNSWICK UNIT 2 RECIRC PUMP SEAL	2,225,714
40	ROBINSON UNDER VESSEL INSULATION	2,040,161
41	HF LEE CONDENSER TUBE CLEANING SYSTEM	2,036,764
42	BRUNSWICK UNIT 2 TURBINE CRANE	2,005,637
43	TOTAL	1,665,669,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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 SPARE START-UP AUXILIARY TRANSFORMER	1,928,559
2	BRUNSWICK UNIT 1 HARDENED VENTS & DRYWELL	1,896,243
3	RICHMOND COUNTY UNIT 3 EXHAUST SYSTEM STACK/CHIMNEY	1,728,653
4	BRUNSWICK ISFSI BANKING IMPROVEMENTS	1,673,860
5	HARRIS UNIT 1 ERFIS INVERTER	1,565,636
6	BRUNSWICK SLIDE FOR LIFE EROSION CONTROL	1,536,535
7	ROBINSON UNIT 2 MBVM CABINET	1,511,840
8	ALERT & NOTIFICATION SYSTEMS	1,497,049
9	ROBINSON UNIT 2 MAKE-UP WATER TREATMENT DCS	1,478,339
10	WALTERS - WICKET GATE AND WEAR PLATE	1,473,879
11	HARRIS EMERGENCY SERVICE WATER PUMP INSTALLATION	1,420,596
12	BRUNSWICK CASWELL BEACH MICROWAVE TOWER	1,400,176
13	BRUNSWICK UNIT 1 INSTRUMENT DRY TUBES	1,376,053
14	BRUNSWICK UNIT 2 SERVICE WATER BAY CONCRETE	1,347,237
15	BRUNSWICK UNIT 1 REMOTE ELECTRIC LIFT & TRAVERSING CRANE	1,323,596
16	ROBINSON ONGOING DRY FUEL- DSC'S	1,317,249
17	BRUNSWICK NON DCS RECORDER	1,295,169
18	HARRIS TURBINE LUBE OIL CONDITIONER	1,229,941
19	BRUNSWICK UNIT 2 REMOTE ELECTRIC LIFT & TRAVERSING CRANE	1,140,613
20	ROBINSON - NORTH STORMWATER HEADER	1,046,326
21	ROXBORO STACKOUT TOWER 3&4	1,037,616
22	BRUNSWICK UNIT 2 5A AND 5B FEEDWATER HEATER ACCESS PLUGS	1,030,991
23	BRUNSWICK UNIT 1 TURBINE CRANE	1,022,330
24	ROBINSON PENETRATION D-5 TEMP POWER	1,001,539
25	PROJECTS LESS THAN $1 MILLION	44,035,798
26	TOTAL PRODUCTION PLANT $1,208,514,540	
27		
28	TRANSMISSION PLANT	
29		
30	ASHEVILLE COMBINED CYCLE	25,115,759
31	WESTERN CAROLINAS RELIABILITY ENCHANCEMENT PROJECT	20,261,408
32	GRANTS CREEK SUB-CONSTRUCT NEW SUBSTATION AND TAPS	13,291,059
33	BRUNSWICK PLANT UNIT 1-RELOCATE LINE TERM	10,827,198
34	HAMLET - ADD NEW BANK #3, TRANSFORMER, & CONTROL BUILDING	8,473,591
35	2017 MOBILE EQUIPMENT	7,477,067
36	SUTTON PLANT TO CASTLE HAYNE LINES	6,654,716
37	ROCKY MOUNT TRANSMISSION CLASS OIL CIRCUIT BREAKERS	6,224,080
38	NEWPORT TO HARLOWE - NEW LINES	6,177,164
39	CLEVELAND MATTHEWS ROAD SUBSTATION	4,739,656
40	RICHMOND - SECURITY ENHANCEMENTS	4,653,357
41	CAPE FEAR TO SILER CITY LINES	3,855,534
42	OTEEN TO WEST ASHEVILLE LINES	3,651,880
43	TOTAL	1,665,669,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	SUMTER TO SCEG EASTOVER LINES	3,468,446
2	JACKSONVILLE CITY TRANSMISSION OIL CIRCUIT BREAKERS	3,432,081
3	CANTON - SECURITY ENHANCEMENTS	2,677,500
4	TILLARY H.E. PLANT - SECURITY ENHANCEMENTS	2,480,666
5	WEATHERSPOON TO REAFORD LINES	2,464,178
6	HARRIS PLANT - INSTALL POWER POTS	2,259,630
7	ASHEBORO TO ASHEBORO EAST LINES	1,958,731
8	FLORENCE MARION LINE CONSTRUCTION	1,641,279
9	MOBILE - AT&T COMMUNICATIONS CIRCUIT PHASE OUT PLAN	1,640,279
10	VEGETATION MASTER PROJECT	1,595,804
11	CAPITAL ASSETS DAMAGED OR DESTROYED DUE TO HURRICANE FLORENCE	1,244,469
12	SPCC RECLASS FUNDING PROJECT	1,180,936
13	JACKSONVILLE - ADD REDUNDANT	1,106,193
14	MILBURNIE & ROXBORO - CIRCUIT BREAKERS	1,094,877
15	ZEBULON - ADD BANK #2	1,088,737
16	AURORA SUBSTATION - SPLIT CAPACITOR BANK INTO TWO BANKS	1,037,886
17	PROJECTS LESS THAN $1 MILLION	21,640,678
18	TOTAL TRANSMISSION PLANT $173,414,839	
19		
20		
21		
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42		
43	TOTAL	1,665,669,162

Schedule Page: 216   Line No.: 4   Column: b

The Green Level -Acquire Land for Substation project (Project 170907A01) represents an adjustment made to a land purchase transaction that offsets to the -$9.3M on FERC Form 1 p.214 Electric Plant Held for Future Use (Line 22d). An adjustment will be made to these accounts in January 2019.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	11,506,301,729	11,506,301,729		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	746,423,277	746,423,277		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	7,723,460	7,723,460		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	204,602,068	204,602,068		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	958,748,805	958,748,805		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	431,559,270	431,559,270		
13	Cost of Removal	169,301,613	169,301,613		
14	Salvage (Credit)	54,870,348	54,870,348		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	545,990,535	545,990,535		
16	Other Debit or Cr. Items (Describe, details in footnote):	12,422,060	12,422,060		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	11,931,482,059	11,931,482,059		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,335,766,305	2,335,766,305		
21	Nuclear Production	4,664,842,986	4,664,842,986		
22	Hydraulic Production-Conventional	46,116,134	46,116,134		
23	Hydraulic Production-Pumped Storage				
24	Other Production	672,515,253	672,515,253		
25	Transmission	816,197,672	816,197,672		
26	Distribution	3,235,148,353	3,235,148,353		
27	Regional Transmission and Market Operation				
28	General	160,895,356	160,895,356		
29	TOTAL (Enter Total of lines 20 thru 28)	11,931,482,059	11,931,482,059		

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

Notes:

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

ARO Depreciation Expense 108/182	217,543,466
Rate case Non-AMI Meter Depreciation True-up	(254,544)
Storm Costs	30,862
SmartGrid Deferrals	180,236
Wayne and Sutton Depreciation	(915,030)
Transmission Expansion Projects Impairment Amortization	287,669
Rotable Fleet Spare Reg Liability Amoritization	1,938,375
SC Rate Case Impact Deferrals	5,668,333
Transfer of Reserve for Externally Funded Decontaminated Decommissioning Expense	(20,340,325)
ABSAT (Coal Ash) Assets Deferrals	189,889
AMI Meter Deferral	272,610
Miscellaneous Depreciation Expense	526
	204,602,068

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

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

Coal Ash COR Reclass to 182/186	(603,330)
Rotable Fleet Spare Transferred Reserve	615,707
Net Gains on disposal of property	(912,437)
Non-AMI Meter NBV Tru-up	7,219,368
Meter Retirements to Reg Asset	5,505,804
Transfer From 111100	261,393
DEP NC Partial Settlement - Imp - Mayo Coal Unit 1	225,834
DEP NC Partial Settlement - Imp - Sutton Blackstart Common	99,282
Miscellaneous Adjustments	10,439
	12,422,060

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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			-7,998
4	Subtotal Capitan Corporation			3,189
5				
6	CaroFund, Inc.	8/15/1995		
7	Common Stock / Equity Contribution			1,678,508
8	Undistributed Earnings			782,225
9	Subtotal CaroFund, Inc.			2,460,733
10				
11	CaroHome, LLC	4/21/1995		
12	Common Stock / Equity Contribution			69,674,735
13	Undistributed Earnings			-52,501,474
14	Subtotal CaroHome, LLC			17,173,261
15				
16	Powerhouse Square, LLC	1/16/1998		
17	Common Stock / Equity Contribution			3,054,401
18	Undistributed Earnings			-2,540,812
19	Subtotal Powerhouse Square, LLC			513,589
20				
21	Duke Energy Progress Receivables, LLC	10/16/2013		
22				
23				
24				
25				
26				
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39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	20,150,772

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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
-110		-8,108		3
-110		3,079		4
				5
				6
		1,678,508		7
56,392		838,617		8
56,392		2,517,125		9
				10
				11
		69,674,735		12
7,338,696		-44,981,435		13
7,338,696		24,693,300		14
				15
				16
		3,054,401		17
-550		-2,541,362		18
-550		513,039		19
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7,394,428		27,726,543		42

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)	242,760,869	220,024,307	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)	436,831,610	443,265,405	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	268,363,304	233,460,148	Generation
8	Transmission Plant (Estimated)	8,780,979	6,512,715	Transmission
9	Distribution Plant (Estimated)	25,156,904	17,370,949	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)	739,132,797	700,609,217	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	134,782	182,270	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	35,393,695	33,384,627	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	1,017,422,143	954,200,421	

Schedule Page: 227 Line No.: 5 Column: b

Assigned to Construction 2017:

Production	$359,658,427
Transmission	20,125,047
Distribution	57,048,136
Total	$436,831,610

Schedule Page: 227 Line No.: 5 Column: c

Assigned to Construction 2018:

Production	$354,813,509
Transmission	24,921,370
Distribution	63,530,526
Total	$443,265,405

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		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	765,841.00	2,275,099	130,958.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,722.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	11,586.00	20,951		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	755,977.00	2,254,148	130,958.00	
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)		114		
45	Gains		41		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020 No. (f)	2020 Amt. (g)	2021 No. (h)	2021 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
130,958.00		130,958.00		3,404,908.00		4,563,623.00	2,275,099	1
								2
								3
				130,958.00		132,680.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						11,586.00	20,951	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
130,958.00		130,958.00		3,535,866.00		4,684,717.00	2,254,148	29
								30
								31
								32
								33
								34
								35
3,786.00		3,786.00		98,436.00		113,580.00		36
				3,786.00		3,786.00		37
								38
						3,786.00		39
3,786.00		3,786.00		102,222.00		113,580.00		40
								41
								42
								43
					38		152	44
					13		54	45
								46

Schedule Page: 228 Line No.: 1 Column: b

Beginning balance includes allowances for Cross State Air Pollution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 18 Column: c

Does not include the $18,450,643 for renewable energy credits consumption expense represented in account 0509213.

Schedule Page: 228 Line No.: 29 Column: b

Ending balance includes allowances for Cross State Air Polution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 29 Column: m

Does not include the $120,428,610 for renewable energy credits represented in account 0158120.

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

Represents allowances withheld in 2018 sold at auction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	31,263.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,260.00		16,469.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	11,621.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22		1,087.00			
23					
24					
25					
26					
27					
28	Total	1,087.00			
29	Balance-End of Year	19,815.00		16,469.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		165,350		
34	Gains		165,350		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						31,263.00		1
								2
								3
11,714.00		11,714.00		11,714.00		52,871.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						11,621.00		18
								19
								20
								21
						1,087.00		22
								23
								24
								25
								26
								27
						1,087.00		28
11,714.00		11,714.00		11,714.00		71,426.00		29
								30
								31
								32
							165,350	33
							165,350	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 1 Column: b

Beginning Balance includes allowances for the Cross State Air Pollution Rule only (Annual and Seasonal).

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

As of January 1, 2017, DE Progress is no longer subject to the requirements of the Cross State Air Pollution Rule Seasonal Nox program.

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

Does not include the $18,450,643 for renewable energy credits consumption expense represented in account 0509213.

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

Ending Balance Includes allowances for the Cross State Air Pollution Rule only (Annual and Seasonal).

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

Does not include the $120,428,610 for renewable energy credits represented in account 0158120.

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

Counterparty	Quantity	Cost of Goods Sold	Total Sales Price
Emissions Advisors, Inc	100	0	$ 300
Dynegy Marketing and Trade LLC	300	0	$60,000
Emissions Advisors, Inc	50	0	$ 9,500
Fathom Energy	637	0	$95,550
	1,087	0	$165,350

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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					

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	34,309,199		407	70,766	330,242
22	Robinson Nuclear Plant	13,982,544		407	173,971	2,015,159
23	(7/1987 - 7/2030)					
24	Brunswick Nuclear Plant	35,107,437		407	547,327	9,669,450
25	(1/1987 - 10/2036)					
26						
27	Auth 12/22/2014 begun 1/1/2014					
28	Cape Fear Fsl Ret, Amort 10 yr	31,409,406	402,771	407	2,970,612	7,454,309
29	Cape Fear Fsl WS, Amor 10-18 yr	9,694,541	139	407	642,390	6,870,589
30	Lee Fossil Retail, Amort 10 yr	42,544,551	579,823	407	3,910,002	9,758,362
31	Lee Fossil WS, Amort 23-31 yr	10,691,956	-88,129	407	348,766	8,047,181
32	Robinson Fsl Ret, Amort 10 yr	46,967,199	201,224	407	6,067,498	22,636,188
33	Robinson Fsl WS, Amort 27 yr	14,636,691		407	553,700	12,456,730
34	Sutton Fsl Ret, Amort 10 yr	50,821,065	2,379,942	407	6,103,979	19,670,791
35	Sutton FS WS, Amort 10-27 yr	15,986,358	856,399	407	981,296	13,125,444
36	Weatherspoon Fsl Ret, Amort 10 yr	11,917,648	128,051	407	966,053	1,635,540
37	Weatherspoon Fsl WS,Amort 22-28yr	3,327,925		407	128,146	2,420,769
38	Cape Fear CombTur Ret, Amort 10yr	-661,277		407	55,624	-595,813
39	Cape Fear Comb Tur WS, Amort 10yr	-211,739		407	-27,690	-138,448
40	Lee CombustionTurb Ret,Amort 10yr	1,359,740		407	257,699	859,225
41	Lee CombustionTurb WS,Amort 10yr	435,384		407	92,701	463,504
42	Morehead CombTurb Ret, Amort 10yr	-157,519		407	2,861	-92,351
43	Morehead CombTurb WS, Amort 10yr	-50,437		407	-350	-1,749
44						
45	auth 11/17/2016 begun 12/1/2016					
46	Harris COLA Ret	40,630,006	-6,087,361	407	3,418,283	31,124,361
47	Harris COLA WS, Amort 10 yr	7,365,795		407	575,441	5,946,220
48						
49	TOTAL	370,106,473	-1,627,141		27,839,075	153,655,703

Schedule Page: 230 Line No.: 21 Column: f

The reported 2017 ending balance/2018 beginning balance has changed because account 0182512 was moved to FERC Pg 230b, 182.2 Unrecovered Plant Node.

Account 0182512 was included on FERC Pg 232 - Regulatory Assets in 2017.

The amount in column (f) includes $70,766 related to Mayo Deferred Cost Current recorded to account 0182512 in 2017.

Schedule Page: 230 Line No.: 28 Column: a

Page 230b Column (a) Lines 31 - 46
Abbreviations used:
Fsl = Fossil
CombTur and CombTurb = Combustion Turbine
Ret = Retail
WS = Wholesale

Schedule Page: 230 Line No.: 28 Column: b

The amount in column (b) includes amortization of Cost of Removal through 12/31/13 totaling ($14,471,177).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	PGSISQ387-FAIR BLUFF SOLAR O&M	95,000			
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Bennettsville System Impact	(4,332)			
23	Blackriver Solar System	11,520			
24	Breeden Solar SIS	(691)			
25	Cabin Creek SIS	(542)			
26	Cardinal Lateral Pipeline-Wake Cty	47,204			
27	Cube Hydro Interconnection study	941			
28	Cumberland 500kV	963			
29	Cumberland County Perry Land	796			
30	Dundarrach System Impact	(365)			
31	Elizabeth Farm LLC - SIS Study	(38)			
32	Facilities Study for Summerton Sol	171			
33	Ford Farm Facilities Study	(65)			
34	Ford Farm Impact Study	(20,694)			
35	Fresh Air E Nash SIS Study	(43)			
36	Fresh Air Energy II - Grifton PV2	78			
37	Fresh Air Energy XXIII - SIS	(82)			
38	Friesian Holdings Q380	8,718			
39	Highest Power SIS	(65,839)			
40	Hobkirk Hill Farm LLC SIS Study	(43)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Ingram Impact Study	(13,460)			
23	Innovative 34 LLC FAC	552			
24	Juniper Solar - SIS	(16)			
25	Melsam Solar - SIS	(16)			
26	Mount Moriah Solar SIS	(60)			
27	Mt Croghan - SIS Study Q426	(41)			
28	NCEMC Interconnection study	1,285			
29	NCEMC Interconnection study	1,150			
30	Old Hundred Solar SIS	(60)			
31	Old Libery Farm SIS Study	(527)			
32	Osborne Solar SIS	(142)			
33	Palmetto Solar Invenergy - Q385	2,138			
34	Palmetto Solar Invenergy Solar	3,441			
35	Paxville Farm Solar Sys Impct Stud	(7,311)			
36	Peacock Solar SIS	(60)			
37	Phobos Solar SIS Study	(527)			
38	Q364 FAC - Mount Olive 2	(429)			
39	Shorthorn Solar - SIS Study	(43)			
40	SIS Crooked Run Solar	(14,053)			

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Slender Branch Solar	1,206			
23	South Cove Farm LLC SIS Study	(43)			
24	Summerton Solar	14,400			
25	Swamp Fox	(72)			
26	System impact - Fair Bluff Solar	(864)			
27	System Impact Study for Q370	(5,151)			
28	Trent River Solar SIS Study	(331)			
29	Virginia Line Solar - SIS	(20)			
30	Bay Tree Impact Study	(16,689)			
31	Homer Solar Impact Study	(12,862)			
32	SIS Slender Branch Solar	81			
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) 04/12/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Fuel Asset (NC Docket E-2, Sub 1031)	10,708,566	113,964,662	Various	119,372,062	5,301,166
2						
3	SFAS 158 Regulatory Assets	429,414,148	133,837,362	Various	21,513,493	541,738,017
4	(NC Docket E-100, Sub 913)					
5						
6	Grid South Deferral SC	3,676,168		407		3,676,168
7						
8	Deferred Fuel Clause NC Retail	120,505,100	312,967,220	254;557	60,675,934	372,796,386
9	(NC Docket E-2, Sub 1173)					
10						
11	Deferred Fuel Clause SC Retail	9,599,697	22,592,317	254;557	8,691,316	23,500,698
12	(SC Docket 2018-1-E)					
13						
14	NC REPS Deferral (NC Docket E-2, Sub 1032)	(2,695,375)	4,183,506	Various	4,398,875	-2,910,744
15						
16	SFAS 143 Regulatory Assets	374,214,327	167,477,207	Various	97,034,662	444,656,872
17	(NC Docket E-2, Sub 826,; SC Docket 2003-84-E)					
18						
19	SFAS 109 Regulatory Assets	162,182,636	229,242,295	Various	218,440,612	172,984,319
20						
21	Accrued Vacation (NC Docket E-2, Sub 859)	42,170,920	751,409	242	1,503,175	41,419,154
22						
23	Gas Pipeline Upgrade	450,209		186,547	54,570	395,639
24	(Amortized over 25 years, ending 2026)					
25						
26	Pollution Control SC (SC Docket No. 2008-435-E)	32,677,776		407	2,513,675	30,164,101
27	(Amortized over 14 years, beginning 2017)					
28						
29	DSM/EE Deferral NC (NC Docket E-2, Sub 1030)	236,558,945	113,735,244	407,408	130,520,238	219,773,951
30						
31	DSM/EE Deferral SC (SC Docket No. 2013-76-E)	27,929,421	18,204,318	407,408	30,803,999	15,329,740
32						
33	Wayne County Plant Deferred Costs NC	2,164,536	2,632,605	Various	4,797,141	
34	(NC Docket E-2, Sub 1026)					
35	(Amortized over 5 years, beginning 2013)					
36						
37	Wayne County Plant Deferred Costs SC	20,615,520	6,441,412	Various	6,730,134	20,326,798
38	(SC Docket 2013-155-E)					
39						
40	Rate Case Cost Deferral (NC Docket E-2, Sub 1142)	248,167	4,493,672	928	1,011,639	3,730,200
41	(Amortized over 5 years, beginning 2018)					
42						
43						
44	TOTAL	3,419,931,113	2,796,821,282		1,951,726,747	4,265,025,648

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Rate Case Cost Deferral (SC Docket 2016-227-E)	122,348		928	30,587	91,761
2	(Amortized over 5 years, beginning 2017)					
3						
4	Nuclear Levelization Deferral NC and SC	35,337,319	191,530,077	Various	180,553,068	46,314,328
5						
6	Sutton Plant Deferred Costs SC	10,745,638	2,223,879	Various	2,726,305	10,243,212
7	(SC Docket 2013-472-E)					
8						
9	Fukushima/Cyber Security Deferral SC	4,729,315	570,727	Various	691	5,299,351
10	(SC Docket 2013-472-E)					
11						
12	Coal Ash Deferred Costs	1,733,304,194	1,079,178,308	Various	762,222,189	2,050,260,313
13	(NC Coal Ash Management Act of 2014)					
14						
15	Interest Rate Swap	5,556,146	23,921,962	Various	24,591,454	4,886,654
16	(NC Docket E-2, Sub 1006; SC Docket 2015-95-E)					
17						
18	Storm Costs Deferral SC Ice Storms	73,180,940	3,782,175	182,186	62,249,702	14,713,413
19	(SC Docket 2014-482-E)			407		
20						
21	NCEMPA Purchase Deferral NC	46,672,896	158,016,801	407	160,297,069	44,392,628
22	(NC Docket E-2, Sub 1176)					
23						
24	NCEMPA Purchase Deferral SC	10,215,877	1,684,634	186,407	1,888,670	10,011,841
25	(SC Docket 2016-227-E)			421		
26						
27	DERP Deferral SC	7,040,578	9,781,208	Various	3,996,998	12,824,788
28	(SC Docket 2015-1-E)					
29						
30	Regulatory Fee Deferral NC	1,795,511	714,409	928	673,364	1,836,556
31	(NC Docket E-2, Sub 1142)					
32						
33	Deferred VOP Costs (SC Docket 2016-227-E)	2,309,590		920	577,398	1,732,192
34						
35	NC Storm Costs Deferral - Hurricane Matthew		47,155,201	Various	19,087,579	28,067,622
36	(NC Docket E-2, Sub 1142)					
37						
38	SC Storm Costs Deferral - Hurricane Matthew		72,259,865	Various	9,271,690	62,988,175
39	(SC Docket 2016-227-E)					
40						
41	Customer Connect Deferral NC		22,080,220	Various	2,038,539	20,041,681
42	(NC Docket E-2, Sub 1142)					
43						
44	TOTAL	3,419,931,113	2,796,821,282		1,951,726,747	4,265,025,648

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	Customer Connect Deferral SC		960,319	Various		960,319
2	(SC Docket 2018-206-E)					
3						
4	Pension Deferred Costs		118,486	Various	118,486	
5						
6	Renewable Energy Certificate Biogas NC		354,577	547	18,837	335,740
7	(NC Docket E-2, Sub 930)					
8						
9	EPA Emission Allowances		1,666,667	254,407	209,449	1,457,218
10	(NC Docket E-2, Sub 1142)					
11						
12	Coal Inventory Deferral NC		283,489	421,456		283,489
13	(NC Docket E-2, Sub 1142)					
14						
15	AMI Meter/Grid Deferred Costs SC		2,272,275	403,421	916,592	1,355,683
16	(SC Docket 2018-205-E ; 2018-206-E)			431		
17						
18	Competetive Procurement of Renewable Energy		855,141	426,912	412,893	442,248
19	(NC House Bill 589)			923		
20						
21	Excess Amortization Asset NC		1,747,700	407		1,747,700
22	(NC Docket E-2, Sub 1142)					
23						
24	Harris COLA SC (SC Docket 2013-472-E)		9,483,255	182	3,395,895	6,087,360
25						
26	ABSAT Projects Deferred Costs NC		882,367	403,421	477,221	405,146
27	(NC Docket E-2, Sub 1142)			431		
28						
29	ABSAT Projects Deferred Costs SC		144,792	403,421	81,275	63,517
30	(SC Docket 2016-196-E)			431		
31						
32	COR Settlement NC		20,060,606	186	636,364	19,424,242
33	(NC Docket E-2, Sub 1142)					
34						
35	COR Settlement SC	18,500,000		186,407	532,576	17,967,424
36	(SC Docket 2016-227-E)					
37						
38	Depreciation Deferral SC		6,218,094	186,403	921,269	5,296,825
39	(SC Docket 2018-204-E)			407		
40						
41	Interest Rate Hedge		3,058,423	181	3,654,954	-596,531
42						
43	NC Solar Rebate (NC House Bill 589)		5,292,396	Various	2,084,108	3,208,288
44	TOTAL	3,419,931,113	2,796,821,282		1,951,726,747	4,265,025,648

Name of Respondent Duke Energy Progress, LLC	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: d
142, 174, 176, 232, 245, 254, 547

Schedule Page: 232 Line No.: 3 Column: d
128,186, 228, 253, 254, 926

Schedule Page: 232 Line No.: 14 Column: d
105, 107, 108, 120, 121, 131, 142, 143, 163, 186, 228, 232, 242, 254 401, 407, 408, 416, 417, 426, 454, 456, 457, 500, 501, 502, 506, 507, 510, 511, 512, 513, 514, 517, 518, 519, 520, 523, 524, 528, 529, 530, 531, 532, 535, 537, 539, 541, 542, 543, 544, 545, 546, 547, 548, 549, 551, 552, 553, 554, 555, 556, 557, 560, 561, 562, 563, 566, 567, 569, 570, 571, 573, 580, 581, 582, 583, 584, 586, 587, 588, 592, 593, 594, 595, 596, 597, 598, 804, 901, 902, 903, 905, 909, 910, 912, 913, 916, 920, 921, 923, 925, 926, 930, 931, 935

Schedule Page: 232 Line No.: 16 Column: d
128, 254, 403, 411

Schedule Page: 232 Line No.: 19 Column: d
190, 219, 236, 253, 254, 255, 282, 283, 409, 410, 411

Schedule Page: 232 Line No.: 33 Column: d
254, 403, 407, 408, 421

Schedule Page: 232 Line No.: 37 Column: d
403, 407, 408, 431

Schedule Page: 232.1 Line No.: 4 Column: d
417, 510, 513, 517, 518, 519, 520, 523, 524, 528, 529, 530, 531, 532

Schedule Page: 232.1 Line No.: 6 Column: d
403, 407, 408, 431

Schedule Page: 232.1 Line No.: 9 Column: d
524, 528, 529, 530, 531, 532, 930

Schedule Page: 232.1 Line No.: 12 Column: d
101, 107, 108, 186, 230, 242, 254, 403, 407, 411, 421, 426, 431

Schedule Page: 232.1 Line No.: 15 Column: d
174, 176, 244, 427

Schedule Page: 232.1 Line No.: 27 Column: d
107, 131, 142, 184, 232, 236, 407, 408, 426, 557, 561, 569, 910, 912, 921, 923, 925, 930

Schedule Page: 232.1 Line No.: 35 Column: d
407, 593, 403, 431

Schedule Page: 232.1 Line No.: 38 Column: d
407, 593, 403, 431

Schedule Page: 232.1 Line No.: 41 Column: d
108, 186, 408, 431, 528, 566, 581, 902, 903, 910, 921, 923, 926

Schedule Page: 232.2 Line No.: 1 Column: d
408, 421, 431, 528, 566, 581, 588, 902, 903, 910, 920, 921, 923, 926

Schedule Page: 232.2 Line No.: 4 Column: d
105, 107, 108, 120, 128, 143, 163, 181, 182, 186, 228, 232, 236, 241, 242, 253, 417, 426, 427, 500, 510, 511, 512, 513, 514, 517, 518, 519, 520, 523, 524, 528, 529, 530, 531, 532, 535, 537, 539, 543, 544, 545, 546, 548, 549, 551, 552, 553, 554, 555, 556, 557, 560, 561, 562, 563, 566, 569, 570, 571, 580, 581, 582, 583, 584, 586, 587, 588, 590, 592, 593, 594, 596, 597, 598, 803, 902, 903, 908, 910, 912, 913, 916, 920, 921, 923, 926, 930, 935

Schedule Page: 232.2 Line No.: 43 Column: d
105, 107, 108, 120, 128, 143, 163, 181, 182, 186, 228, 232, 236, 241, 242, 253, 417, 426, 427, 500, 510, 511, 512, 513, 514, 517, 518, 519, 520, 523, 524, 528, 529, 530, 531, 532, 535, 537, 539, 543, 544, 545, 546, 548, 549, 551, 552, 553, 554, 555, 556, 557, 560, 561, 562, 563, 566, 569, 570, 571, 580, 581, 582, 583, 584, 586, 587, 588, 590, 592, 593, 594, 596, 597, 598, 803, 902, 903, 908, 910, 912, 913, 916, 920, 921, 923, 926, 930, 935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	328,188		182	328,188	
2						
3	Interest Rate Hedges	46,042,009	8,747,195	427	21,255,565	33,533,639
4						
5	Accounts in Process of Reclass	268,250	15,655	Various	119,370	164,535
6						
7	Deferred Rate Case Expenses	4,259,185	3,027,227	Various	5,281,720	2,004,692
8						
9	Gas Pipeline Charges	3,967,880	54,570	547	535,526	3,486,924
10	2001-2026 amortization period					
11						
12	Workers Comp Insurance Reimb	3,159,771	1,664,719	Various		4,824,490
13						
14	Fukushima Pooled Inventory	1,805,782		232		1,805,782
15						
16	Cost of Removal Settlement - NC	20,000,000	696,970	Various	20,696,970	
17						
18	Deferred Coal Ash Remediation	241,716,118	42,635,696	Various	284,351,814	
19						
20	NCEMPA SC Equity Reserve	-3,928,022	1,459,530	Various	1,659,102	-4,127,594
21						
22	Deferred Storm Costs	81,907,822	1,673,812,948	Various	1,286,075,205	469,645,565
23						
24	Solar Equity Reserve	-5,399,484	5,399,484	186	4,768,566	-4,768,566
25						
26	Gypsum Settlement Agreement		29,172,679	557		29,172,679
27						
28	Camp Lejeune Incremental Costs		8,415,857	417	71,936	8,343,921
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47	Misc. Work in Progress	174,127				418,385
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	394,301,626				544,504,452

Schedule Page: 233 Line No.: 5 Column: d

Offset by 107, 108, 163, 232, 236, 517, 519, 520, 523, 524, 528, 529, 530, 531, 532

Schedule Page: 233 Line No.: 7 Column: d

Offset by 105, 107, 108, 120, 124, 128, 131, 142, 143, 163, 181, 182, 183, 184, 185, 228, 232, 236, 241, 242, 253, 408, 417, 421, 426, 454, 456, 457, 500, 502, 506, 510, 511, 512, 513, 514, 517, 518, 519, 520, 523, 524, 528, 529, 530, 531, 532, 535, 537, 539, 541, 542, 543, 544, 545, 546, 548, 549, 551, 552, 553, 554, 555, 556, 557, 560, 561, 562, 563, 566, 567, 569, 570, 571, 573, 580, 581, 582, 583, 584, 586, 587, 588, 590, 592, 593, 594, 595, 596, 597, 598, 803, 804, 901, 902, 903, 905, 908, 909, 910, 912, 913, 916, 920, 921, 923, 925, 926, 928, 930, 931, 935

Schedule Page: 233 Line No.: 12 Column: d

Offset by 228, 242, 925

Schedule Page: 233 Line No.: 16 Column: d

Offset by 182, 403, 407, 431, 593

Schedule Page: 233 Line No.: 18 Column: d

Offset by 182, 242, 254, 407, 421, 426, 431, 501

Schedule Page: 233 Line No.: 20 Column: d

Offset by 182, 407, 421

Schedule Page: 233 Line No.: 22 Column: d

Offset by 105, 107, 108, 120, 121, 142, 143, 163, 182, 183, 184, 185, 228, 232, 242, 401, 403, 408, 416, 417, 426, 431, 457, 500, 501, 502, 506, 507, 510, 511, 512, 513, 514, 517, 518, 519, 520, 523, 524, 528, 529, 530, 531, 532, 535, 537, 539, 541, 542, 543, 544, 545, 546, 547, 548, 549, 551, 552, 553, 554, 556, 557, 560, 561, 562, 563, 566, 567, 569, 570, 571, 573, 580, 581, 582, 583, 584, 585, 586, 587, 588, 589, 590, 591, 592, 593, 594, 595, 596, 597, 598, 803, 804, 870, 901, 902, 903, 905, 908, 910, 912, 920, 921, 923, 926, 930, 999

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	1,775,392,682	1,864,956,280
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,775,392,682	1,864,956,280
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)	1,775,392,682	1,864,956,280

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
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						4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	2018 Expenses	1
7	CP&L Customer Stock Ownership Plan:	
8	1984 Expenses	-9,575
9	1985 Expenses	-2,990
10	CP&L Stock Purchase Savings Plan - 1985 Expenses	-32,166
11	Issuance of Common Stock - 1985 Expenses	-141,781
12	CP&L Common Stock Sale to Retail Customers:	
13	1986 Expenses	-9,052
14	1988 Expenses	-9,548
15	CP&L Common Stock Split - 1993 Expenses	-456,341
16	Issuance of Common Stock - 1999 Expenses	-3,511
17	Listing Additional Shares on the New York Stock Exchange:	
18	2000 Expenses	-21,961
19	Transfer of Board of Directors' Compensation Plan - 2000	4,690,089
20	Reclass Equity Accounts - 2001	115,000,000
21	Contributions Related to Employee Stock Ownership Plan:	
22	2000	2,977,924
23	2001	22,585,247
24	2002	25,268,396
25	2003	19,838,656
26	2004	22,183,955
27	2005	19,528,622
28	2006	18,781,253
29	2007	20,167,207
30	2008	16,057,376
31	2009	10,138,259
32	2010	9,693,593
33	North Carolina Natural Gas Divestiture - 2003	3,297,692
34	Stock Options Income Tax - 2004	199,761
35	Non-Cash Dividend to Parent - 2005	-17,069,331
36	Stock Based Compensation:	
37	2005	3,378,817
38	2006	10,150,080
39	2007	24,072,823
40	TOTAL	2,784,376,572

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	2008	12,752,805
2	Stock Based Compensation:	
3	2009	15,355,354
4	2010	11,429,228
5	2011	14,295,722
6	2012	11,050,101
7	2015 Conversion of Duke Energy Progress to a limited liability company	1,759,809,101
8	Capital Infusion from Duke Energy Corporation	625,000,000
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40	TOTAL	2,784,376,572

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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)
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2		
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22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Account 221 - First Mortgage and Pollution Control Bonds:		
2			
3	4.000% Wake 2002 Pollution Control Bonds Due 6/1/2041	48,485,500	603,686
4			
5	5.3% Series Due 1/15/2019	600,000,000	3,900,000
6			552,000 D
7	8.625% Series Due 9/15/2021	100,000,000	564,887
8			375,000 D
9	3% Series Due 9/15/2021	500,000,000	3,250,000
10			860,000 D
11	2.8% Series Due 5/15/2022	500,000,000	3,900,000
12			1,125,000 D
13	6.125% Series Due 9/15/2033	200,000,000	2,048,641
14			3,104,000 D
15	5.7% Series Due 4/1/2035	200,000,000	1,928,655
16			518,000 D
17	6.3% Series Due 4/1/2038	325,000,000	2,843,750
18			581,750 D
19	4.1% Series Due 5/15/2042	500,000,000	5,025,000
20			2,480,000 D
21	4.1% Series Due 3/15/2043	500,000,000	4,330,566
22			3,675,000 D
23	4.375% Series Due 3/30/2044	400,000,000	3,563,688
24			3,500,000 D
25	4.150% Series Due 12/1/2044	500,000,000	4,443,471
26			4,375,000 D
27	3.25% Series Issued 8/13/2015 Due 8/15/2025	500,000,000	2,812,775
28			3,250,000 D
29	4.2% Series Issued 8/13/2015 Due 8/15/2045	700,000,000	6,027,165
30			6,125,000 D
31	3.7% Series Issued 9/16/2016	450,000,000	3,836,700
32			3,937,500 D
33	TOTAL	8,123,485,500	104,494,937

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	3.60% Series Issued 9/5/2017 Due 9/15/2047	500,000,000	4,247,291
2			1,050,000 D
3	Floating Rate Series Due 9/8/2020 (2.862% at 12/31/2018)	300,000,000	4,375,000
4			
5	DEP 300M 3.375% Issued 8/9/2018 Due 9/1/2023	300,000,000	1,333,157
6			1,800,000 D
7	DEP 500M 3.70% Issued 8/9/2018 Due 9/1/2028	500,000,000	2,721,928
8			3,250,000 D
9	SUBTOTAL - Account 221	7,623,485,500	102,314,610
10			
11	Account 222 - Reacquired Bonds		
12	None		
13			
14	Account 223 - Advances to Associated Companies:		
15	Commercial Paper Series Due 1/30/2020 (2.708% at 12/31/2018)	150,000,000	
16			
17	SUBTOTAL - Account 223	150,000,000	
18			
19	Account 224 - Other Long-Term Debt:		
20	DEP Receivables 300M Due 2/12/2019	300,000,000	1,923,727
21			
22	700M Term Loan Due 12/31/2020 (3.0401% at 12/31/2018)	50,000,000	256,600
23			
24	SUBTOTAL - Account 224	350,000,000	2,180,327
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	8,123,485,500	104,494,937

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	1,939,400	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	18,284,894	11
						12
09/11/2003	09/15/2033	09/11/2003	09/15/2033	200,000,000	12,250,000	13
						14
03/22/2005	04/01/2035	03/22/2005	04/01/2035	200,000,000	11,400,000	15
						16
03/13/2008	04/01/2038	03/13/2008	04/01/2038	325,000,000	20,924,460	17
						18
05/15/2012	05/15/2042	05/15/2012	05/15/2042	500,000,000	20,500,000	19
						20
03/12/2013	03/15/2043	03/15/2013	03/15/2043	500,000,000	21,529,000	21
						22
03/06/2014	03/30/2044	03/06/2014	03/30/2044	400,000,000	17,500,000	23
						24
11/20/2014	11/20/2014	11/20/2014	12/01/2044	500,000,000	20,750,000	25
						26
8/13/2015	8/15/2025	8/13/2015	8/15/2025	500,000,000	16,250,000	27
						28
8/13/2015	8/15/2045	8/13/2015	8/15/2045	700,000,000	29,400,000	29
						30
9/16/2016	10/15/2046	9/16/2016	10/15/2046	450,000,000	16,650,000	31
						32
				8,123,485,000	318,248,105	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
9/8/2017	9/15/2047	9/8/2017	9/15/2047	500,000,000	18,000,000	1
						2
9/5/2017	9/8/2020	9/5/2017	9/8/2020	300,000,000	7,051,982	3
						4
8/9/2018	9/1/2023	8/9/2018	9/1/2023	300,000,000	3,993,750	5
						6
8/9/2018	9/1/2028	8/9/2018	9/1/2018	500,000,000	7,272,881	7
						8
				7,623,485,000	305,866,384	9
						10
						11
						12
						13
						14
12/9/2015	1/30/2020	12/9/2015	1/30/2020	150,000,000	3,398,341	15
						16
				150,000,000	3,398,341	17
						18
						19
12/20/2013	2/12/2019	12/20/2013	2/12/2019	300,000,000	8,907,377	20
						21
12/14/2018	12/31/2020	12/14/2018	12/31/2020	50,000,000	76,003	22
						23
				350,000,000	8,983,380	24
						25
						26
						27
						28
						29
						30
						31
						32
				8,123,485,000	318,248,105	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 Line No.: 31 Column: a

Bond issuance approved pursuant to NCUC order issued in Docket Number E-2, Sub 1049 on July 30, 2014 and PSCSC Docket 2014-300-E on August 22, 2014.

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	667,036,191
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	832,083,837
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-165,047,646
28	Show Computation of Tax:	
29		
30	21% of Line 27	-34,660,006
31	Prior Year Federal Tax Adjustment - Primarily Prior Year Tax True-Ups	-36,776,972
32		
33	Total Federal Income Tax	-71,436,978
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Provision for Deferred Income Taxes	(239,434,862)
Provision for Current Federal Income Taxes	71,436,978
Provision for Current State Income Taxes	2,658,575
AFUDC Equity	56,812,523
AFUDC Interest	25,699,616
Benefits Accruals	22,870,033
Book Depreciation/Amortization	(806,034,186)
Camp Lejeune Deferred Costs	8,343,921
Charitable Contribution Accruals	9,989,687
Coal Ash Spend, Net of Capitalized Portion	(3,002,124)
COLI Adjustments	4,656,885
Contributions in Aid of Construction	(53,757,852)
Deferred Compensation	1,662,507
Deferred Fuel	266,977,372
DOE Cash Grant	(6,138,951)
End of Life Nuclear Fuel Cost Reserve	(13,072,784)
Equipment/T&D Repairs	260,200,000
Impairment	(3,594,429)
Investment Tax Credit Amortization	3,355,660
Lawsuit Contingency	(70,463,960)
Meals & Entertainment	(3,300,000)
Non-Qualified Nuclear Decommissioning--Contributions/Earnings	2,655,665
Nuclear Fuel Book Burned	(184,163,880)
Rate Refunds	(14,959,840)
Regulatory Asset - ABSAT	468,663
Regulatory Asset - AMI/Non-AMI Meters	12,887,944
Regulatory Asset - COR Settlement	(83,016,158)
Regulatory Asset - Customer Connect	8,580,600
Regulatory Asset - Depreciation Deferral	5,296,826
Regulatory Asset - Energy Efficiency	(29,384,676)
Regulatory Asset - Environmental	29,172,679
Regulatory Asset - FAS 158	(18,709,572)
Regulatory Asset - Grid Costs	889,139
Regulatory Asset - Harris COLA	(3,993,723)
Regulatory Asset - MyHER Program	(5,795,684)
Regulatory Asset - NCEMPA Purchase Deferrals	(2,683,876)
Regulatory Asset - Nuclear Levelization	10,977,009
Regulatory Asset - Plant Related Retirements	(18,593,069)
Regulatory Asset - Rate Case Expenses	2,944,653
Regulatory Asset - SC Pollution Control Deferral	(2,513,675)
Regulatory Asset - Solar Rebate Costs	3,208,288
Regulatory Asset - Wayne & Sutton Deferrals	(2,884,918)
Regulatory Liability - Rate Case Expenses	(5,200,389)
Renewable Energy Liability	(21,711,087)
Returns on State Excess Deferred Income Taxes	(2,515,760)
SC Distributive Energy Resource Program	5,784,210
Self Developed Software	37,909,282
Severance Accrual	(40,171,739)
Spent Fuel Canisters	(17,268,845)
Storm Cost Deferral	500,801,552
Tax Depreciation/Amortization	1,118,555,434

Tax Gains/Losses (Cost of Removal)	167,904,084
Tax Interest Capitalized	(46,354,734)
Net Operating Loss Utilization/Deferral	(112,071,543)
Other Items	176,368
Total Differences Between Book & Taxable Income	**832,083,837**

Allocations of consolidated tax liability are based on the percentage method of allocation under Treasury Regulation Section 1.1502-33(d)(3), with a fixed percentage of 100 percent, in conjunction with the income method under Treasury Regulation Section 1.1552-1(a)(1).

For members of the affiliated group, see corporations controlled by respondent, page 103.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	3,714,320		-71,436,978	-107,144,216	-34,413,328
3	Unemployment	3,774		185,424	-711,153	-896,345
4	Highway Use			61,024	61,024	
5	Social Security	5,816,274		39,392,513	40,641,291	157,579
6	SUBTOTAL	9,534,368		-31,798,017	-67,153,054	-35,152,094
7						
8	NORTH CAROLINA:					
9	Income			-2,203,521	-4,181,639	-1,415,660
10	Property	17,008,589		66,551,096	80,569,559	-1,932,526
11	Franchise	2,776,458		15,989,969	16,060,590	-2,400,000
12	Unemployment	800		64,295	45,620	
13	Municipal License	-152,338		365,611	365,611	
14	Other Taxes			-5,969,295	-5,969,295	
15	SUBTOTAL	19,633,509		74,798,155	86,890,446	-5,748,186
16						
17	SOUTH CAROLINA:					
18	Income	281,988		-2,380,173	-1,257,267	840,918
19	Property	33,015,341		35,443,255	33,024,292	-249,259
20	Public Utility Corp Licenses	57,397		-4,233		
21	Unemployment	1,252		74,123	77,231	
22	KWH Electric Power			2,222,093	2,222,093	
23	Other Taxes			-1,580	-1,580	
24	Municipal License	7,572,351			10,520,264	11,384,452
25	Privilege License	-803,953		1,007,526	-262,902	1,496,337
26	SUBTOTAL	40,124,376		36,361,011	44,322,131	13,472,448
27						
28	OTHER STATES:					
29	FIN 48	1,370,704				
30	Unemployment			4,736	22,355	
31	Other Taxes			-63,286	-63,286	
32	SUBTOTAL	1,370,704		-58,550	-40,931	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	70,662,957		79,302,599	64,018,592	-27,427,832

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				
(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)	Line No.
						1
5,008,230		-66,292,964			-5,144,014	2
4,006		185,424				3
		61,024				4
4,725,075		39,392,513				5
9,737,311		-26,654,003			-5,144,014	6
						7
						8
562,458		-1,684,000			-519,521	9
1,057,600		64,641,728			1,909,368	10
305,837		15,989,969				11
19,475		64,295				12
-152,338		365,611				13
		-5,969,363			68	14
1,793,032		73,408,240			1,389,915	15
						16
						17
		-2,254,471			-125,702	18
35,185,045		35,391,631			51,624	19
53,164		-4,233				20
-1,856		74,123				21
		2,222,093				22
		-1,580				23
8,436,539						24
1,962,812		1,007,526				25
45,635,704		36,435,089			-74,078	26
						27
						28
1,370,704						29
-17,619		4,736				30
		-63,286				31
1,353,085		-58,550				32
						33
						34
						35
						36
						37
						38
						39
						40
58,519,132		83,130,776			-3,828,177	41

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

Offset to account 146	50,050,692
Offset to account 143	(84,600,893)
Offset to account 190	136,873
	(34,413,328)

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

Offset to account 242	(869,919)
Offset to account 254	(26,426)
	(896,345)

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

Offset to account 120	1,919
Offset to account 182	(29,394)
Offset to account 242	185,398
Offset to account 254	(344)
	157,579

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

Offset to account 146

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

Offset to account 146	(1,811,904)
Offset to account 182	(120,622)
	(1,932,526)

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

Jurisdictional reallocation NC to SC

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

Offset to account 146

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

Offset to account 146	(132,342)
Offset to account 182	(116,917)
	(249,259)

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

Offset to account 142

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

Jurisdictional reallocation NC to SC	2,400,000
Offset to account 143	(512,597)
Offset to account 190	(391,066)
	1,496,337

Schedule Page: 262 Line No.: 33 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 – 796,280 Excluded from Balance at Beginning of Year (column b)
Sales and Use Tax Payable – 759,541 Excluded from Balance at End of Year (column g)

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	2,852,029			411.4	572,977	
4	7%						
5	10%	54,309,404			411.4	2,211,520	
6	6%	129,730			411.4	4,369	
7		86,039,746		2,112,850		566,794	73,891
8	TOTAL	143,330,909		2,112,850		3,355,660	73,891
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	8%	5,601,040			411.4	566,794	
11	30%	80,438,706	190	2,112,850			73,891
12	TOTAL	86,039,746		2,112,850		566,794	73,891
13							
14							
15							
16							
17							
18							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
2,279,052			3
			4
52,097,884			5
125,361			6
87,659,693			7
142,161,990			8
			9
5,034,246			10
82,625,447			11
87,659,693			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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Schedule Page: 266 Line No.: 11 Column: g

The 2017 Federal Tax Return included additional cost basis that was allocated to the Elm City solar project originally reported on the 2016 Federal Tax Return.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Credit - Smart Grid	1,534,126	143.6			1,534,126
2						
3	CATV Pole Rent	3,805,662	Various	3,801,000	3,664,539	3,669,201
4						
5	Environmental Reserve for					
6	Manufactured Gas Plants	338,244	462.5	400,412	357,952	295,784
7						
8	NC Tax Rate Change	5,043,571	Various	9,946,560	4,902,989	
9						
10	Tariff Admin	195,000	None	195,000		
11						
12	Piedmont Natural Gas Merger					
13	Donation Commitment	14,750,000	426.1	7,489,687		7,260,313
14						
15	MYHER EE Program		456.5	700,000	6,495,684	5,795,684
16						
17	Extended Payment Plan					
18	Weather Protect		Various	4,818	684,998	680,180
19						
20	Minor Items	123,188	Various	1,517,547	2,003,883	609,524
21						
22						
23						
24						
25						
26						
27						
28						
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33						
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36						
37						
38						
39						
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42						
43						
44						
45						
46						
47	TOTAL	25,789,791		24,055,024	18,110,045	19,844,812

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	04/12/2019	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
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							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) 04/12/2019	Year/Period of Report End of 2018/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	2,555,356,409	433,962,183	286,133,043
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,555,356,409	433,962,183	286,133,043
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,555,356,409	433,962,183	286,133,043
10	Classification of TOTAL			
11	Federal Income Tax	2,292,118,387	383,672,191	251,740,211
12	State Income Tax	263,238,022	50,289,992	34,392,832
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
6,166,031	930,688	254	21,042,766	182	8,299,010	2,695,677,136	2
							3
							4
6,166,031	930,688		21,042,766		8,299,010	2,695,677,136	5
							6
							7
							8
6,166,031	930,688		21,042,766		8,299,010	2,695,677,136	9
							10
5,435,241	820,384		19,357,765		7,295,754	2,416,603,213	11
730,790	110,304		1,685,001		1,003,256	279,073,923	12
							13

NOTES (Continued)

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

254 - North Carolina Excess Deferred Income Taxes	$1,331,151
254 - Federal Excess Deferred Income Taxes	19,711,615
Total	$21,042,766

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	1,102,510,086	342,260,150	141,949,239
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,102,510,086	342,260,150	141,949,239
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)	1,102,510,086	342,260,150	141,949,239
20	Classification of TOTAL			
21	Federal Income Tax	971,842,119	301,861,645	127,018,004
22	State Income Tax	130,667,967	40,398,505	14,931,235
23	Local Income Tax			

NOTES

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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
	8,613,216	146/254	9,082,836	182	2,502,674	1,287,627,619	3
							4
							5
							6
							7
							8
	8,613,216		9,082,836		2,502,674	1,287,627,619	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
	8,613,216		9,082,836		2,502,674	1,287,627,619	19
							20
	7,631,311		6,240,768		2,206,066	1,135,019,747	21
	981,905		2,842,068		296,608	152,607,872	22
							23

NOTES (Continued)

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

146 - Intercompany Transactions	$2,746,183
254 - North Carolina Excess Deferred Income Taxes	1,988,126
254 - Federal Excess Deferred Income Taxes	4,348,527
Total	$9,082,836

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	EPA Emission Allowances (NC Docket E-2, Sub 1023)	1,042,684	407	1,042,782	98	
2	Amortized over 5 years ending 2018					
3						
4	SFAS 109 Regulatory Liabilties	70,004,969	Various	101,907,928	98,504,102	66,601,143
5						
6	Deferred Fuel Clause NC Retail	1,168,981	182,557	1,238,388	69,407	
7	(NC Docket E-2, Sub 1173)					
8						
9	Deferred Fuel Clause SC Retail		182,557		383,896	383,896
10	(SC Docket 2018-1-E)					
11						
12	DOE Refund Deferral (NC Docket E-2, Sub 1023)	1,699,384	Various	1,699,384		
13	Amortized over 7 years ending 2018					
14						
15	SFAS 143 Regulatory Liabilities	15,264,104	182,407			15,264,104
16	(NC Docket E-2, Sub 826 ; SC Docket 2003-84-E)					
17						
18	Nuclear Decommissioning Trust - Unrealized Gains	973,250,031	128,182	231,318,049	61,780,562	803,712,544
19	(NC Docket E-2, Sub 826 ; SC Docket 2003-84-E)					
20						
21	NC REPS Deferral (NC Docket E-2, Sub 1032)	110,690,580	Various	31,140,285	34,736,469	114,286,764
22						
23	Nuclear Fuel Last Core Reserve	36,987,889	407	2,017,521	15,090,305	50,060,673
24	(NC Docket E-2, Sub 1023)					
25						
26	Harris Land Sale Gains (NC Docket E-2, Sub 1023)	641,435	407	898,009	256,574	
27	Amortized over 5 years ending 2018					
28						
29	NC Tax Rate Change (NC Docket E-2, Sub 1046)	145,125,138	Various	409,703,633	387,603,397	123,024,902
30						
31	OPEB Regulatory Liability	(68,965)	Various	93,501,946	186,903,127	93,332,216
32						
33	Rotable Fleet Spare (NC Docket E-2, Sub 998A)	1,964,006	108,403	2,959,479	2,683,434	1,687,961
34						
35	Income Tax Reform (NC Docket M-100, Sub 148)	1,800,593,397	Various	15,947,922,218	*,***,***,***	909,494,352
36						
37	Excess Accumulated Deferred Income Tax		Various	14,943,391,873	*,***,***,***	936,601,309
38	(NC Docket E-2, Sub 1142)					
39						
40						
41	TOTAL	3,158,363,633		31,819,828,808	31,782,309,298	3,120,844,123

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	Open Interest Rate Swap		Various	51,087,313	52,281,183	1,193,870
2	(NC Docket E-2, Sub 1006 ; SC Docket 2015-95-E)					
3						
4	Excess Amortization Liability		407		5,200,389	5,200,389
5	(NC Docket E-2, Sub 1142)					
6						
7						
8						
9						
10						
11						
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37						
38						
39						
40						
41	TOTAL	3,158,363,633		31,819,828,808	31,782,309,298	3,120,844,123

Schedule Page: 278 Line No.: 4 Column: c
182, 190, 219, 236, 253, 254, 255, 281, 282, 283, 409, 410, 411

Schedule Page: 278 Line No.: 12 Column: c
408, 518, 519, 520, 524, 528, 529, 530, 531, 532, 903, 920, 921, 923, 926, 929

Schedule Page: 278 Line No.: 21 Column: c
158, 182, 407, 456, 509

Schedule Page: 278 Line No.: 29 Column: c
165, 182, 190, 219, 236, 253, 254, 255, 281, 282, 283, 409, 410, 411

Schedule Page: 278 Line No.: 31 Column: c
128, 182, 219, 228, 253, 926

Schedule Page: 278 Line No.: 35 Column: c
182, 190, 219, 236, 253, 254, 255, 281, 282, 283, 409, 410, 411

Schedule Page: 278 Line No.: 35 Column: e
$15,056,823,173

Schedule Page: 278 Line No.: 37 Column: c
182, 190, 219, 236, 253, 254, 255, 281, 282, 283, 409, 410, 411, 421, 431

Schedule Page: 278 Line No.: 37 Column: e
$15,879,993,182

Schedule Page: 278.1 Line No.: 1 Column: c
142, 174, 176, 182, 232, 245, 254, 547

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	2,100,384,584	1,818,028,091
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,282,477,747	1,184,079,182
5	Large (or Ind.) (See Instr. 4)	670,733,191	623,850,424
6	(444) Public Street and Highway Lighting	19,883,833	19,637,514
7	(445) Other Sales to Public Authorities	94,131,859	81,095,376
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,167,611,214	3,726,690,587
11	(447) Sales for Resale	1,511,358,379	1,257,931,458
12	TOTAL Sales of Electricity	5,678,969,593	4,984,622,045
13	(Less) (449.1) Provision for Rate Refunds	118,958,671	
14	TOTAL Revenues Net of Prov. for Refunds	5,560,010,922	4,984,622,045
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,582,371	8,481,360
17	(451) Miscellaneous Service Revenues	6,165,627	7,667,672
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	35,963,712	41,498,063
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-1,014,686	9,560,739
22	(456.1) Revenues from Transmission of Electricity of Others	72,713,350	73,854,633
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	122,410,374	141,062,467
27	TOTAL Electric Operating Revenues	5,682,421,296	5,125,684,512

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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
18,717,246	17,372,065	1,330,794	1,309,968	2
				3
14,139,566	13,945,850	234,714	231,945	4
10,420,725	10,417,125	4,064	4,122	5
76,562	80,125	1,434	1,456	6
1,473,179	1,454,845	5	5	7
				8
				9
44,827,278	43,270,010	1,571,011	1,547,496	10
24,505,471	23,552,726	9	14	11
69,332,749	66,822,736	1,571,020	1,547,510	12
				13
69,332,749	66,822,736	1,571,020	1,547,510	14

Line 12, column (b) includes $ -13,507,473 of unbilled revenues.

Line 12, column (d) includes -366,735 MWH relating to unbilled revenues

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

Includes $6,264,866 of service charges

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

Includes ($5,795,684) of North Carolina Energy Efficiency Program Deferred Revenue partially offset by $1,611,605 of contribution in aid of construction revenue, $1,475,749 of liquidated damages and penalties from solar interconnection agreements, $994,278 of electric revenue from cogeneration/small power producers, and $270,645 from North Carolina Coal Inventory Rider Revenue

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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					
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38					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	18,856,094	2,077,021,244	1,327,224	14,207	0.1102
3	SLR	17,145	6,567,425	3,570	4,803	0.3831
4	ALS	66,246	21,012,267			0.3172
5	Unbilled Revenue	-222,239	-12,540,737			0.0564
6	TOTAL RESIDENTIAL	18,717,246	2,092,060,199	1,330,794	14,065	0.1118
7						
8	Commercial					
9	ALS	245,793	52,371,051			0.2131
10	APH-TES	2,066	138,228	3	688,667	0.0669
11	CH-TOUE	8,707	1,244,444	226	38,527	0.1429
12	CS	2,736	403,999	89	30,742	0.1477
13	LGS	1,257,436	92,077,793	98	12,830,980	0.0732
14	MGS	2,802,730	280,595,069	18,304	153,121	0.1001
15	SFLS	1,285	241,438	95	13,526	0.1879
16	SGS	9,823,509	828,190,825	213,338	46,047	0.0843
17	SI	59,112	7,240,853	1,142	51,762	0.1225
18	SLS	12,151	4,297,204	1,194	10,177	0.3537
19	TFS	178	34,977	103	1,728	0.1965
20	TSS	211	19,987	33	6,394	0.0947
21	GS	3,483	454,510	89	39,135	0.1305
22	Unbilled Revenue	-79,831	119,200			-0.0015
23	TOTAL COMMERCIAL	14,139,566	1,267,429,578	234,714	60,242	0.0896
24						
25	Industrial					
26	ALS	19,182	3,359,389			0.1751
27	LGS	7,998,981	478,019,744	249	32,124,422	0.0598
28	MGS	506,879	50,353,403	1,205	420,646	0.0993
29	SGS	1,947,657	138,296,922	2,564	759,617	0.0710
30	SI	2,456	287,542	23	106,783	0.1171
31	SLS	127	23,518	19	6,684	0.1852
32	GS	197	29,569	4	49,250	0.1501
33	Unbilled Revenue	-54,754	-914,311			0.0167
34	TOTAL INDUSTRIAL	10,420,725	669,455,776	4,064	2,564,155	0.0642
35						
36	Public Street Lighting					
37	SLS	72,001	19,502,395	589	122,243	0.2709
38	TSS	5,221	476,506	845	6,179	0.0913
39	Unbilled Revenue	-660	-161,300			0.2444
40	TOTAL PUBLIC STREET LIGHTING	76,562	19,817,601	1,434	53,391	0.2588
41	TOTAL Billed	45,194,013	4,181,118,687	1,571,011	28,767	0.0925
42	Total Unbilled Rev.(See Instr. 6)	-366,735	-13,507,473	0	0	0.0368
43	TOTAL	44,827,278	4,167,611,214	1,571,011	28,534	0.0930

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	210			0.1050
4	LGS	1,482,427	94,139,154	5	296,485,400	0.0635
5	Unbilled Revenue	-9,250	-10,325			0.0011
6	TOTAL OTHER PUBLIC	1,473,179	94,129,039	5	294,635,800	0.0639
7						
8						
9						
10						
11						
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15						
16						
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31						
32						
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34						
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36						
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38						
39						
40						
41	TOTAL Billed	45,194,013	4,181,118,687	1,571,011	28,767	0.0925
42	Total Unbilled Rev.(See Instr. 6)	-366,735	-13,507,473	0	0	0.0368
43	TOTAL	44,827,278	4,167,611,214	1,571,011	28,534	0.0930

Schedule Page: 304   Line No.: 6   Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue exlcuded from this line is $8,324,385.

Schedule Page: 304   Line No.: 23   Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue exlcuded from this line is $15,048,169.

Schedule Page: 304   Line No.: 34   Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue exlcuded from this line is $1,277,415.

Schedule Page: 304   Line No.: 40   Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue exlcuded from this line is $66,232.

Schedule Page: 304.1   Line No.: 6   Column: c

This line will not tie to the corresponding class revenue on page 300 due to the inclusion of REPS revenues. REPS revenue is a per customer charge and is not allocated by rate code. The REPS revenue exlcuded from this line is $2,820.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	Non-Requirement Sales					
2	Duke Energy Carolinas, LLC	LF	190			
3	Duke Energy Carolinas, LLC	AD	190			
4	PJM Interconnection L.L.C.	OS	7			
5	PJM Interconnection L.L.C.	AD	7			
6	South Carolina Electric & Gas	OS	97			
7						
8	Requirement Sales					
9	Town of Black Creek, NC	RQ	174	0	0	0
10	Town of Black Creek, NC	RQ	174			
11	City of Camden, SC	RQ	197	38	39	38
12	City of Camden, SC	RQ	197			
13	PWC of the City of Fayetteville	RQ	184	371	376	371
14	PWC of the City of Fayetteville	RQ	184			
	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) 04/12/2019	Year/Period of Report End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	French Broad EMC	RQ	210	75	98	93
2	French Broad EMC	RQ	210			
3	Haywood EMC	RQ	180	14	23	18
4	Haywood EMC	RQ	180			
5	Town of Lucama, NC	RQ	175	0	0	0
6	Town of Lucama, NC	RQ	175			
7	NC Electric Membership Corporation	OS	4			
8	NC Electric Membership Corporation	AD	4			
9	NC Electric Membership Corporation	RQ	134	970	970	970
10	NC Electric Membership Corporation	RQ	134			
11	NC Electric Membership Corporation	RQ	182	740	759	738
12	NC Electric Membership Corporation	RQ	182			
13	NC Eastern Municipal Power Agency	RQ	200	1094	1286	1093
14	NC Eastern Municipal Power Agency	RQ	200			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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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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.
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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 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	Piedmont EMC	RQ	172	19	21	19
2	Piedmont EMC	RQ	172			
3	Town of Sharpsburg, NC	RQ	176	0	0	0
4	Town of Sharpsburg, NC	RQ	176			
5	Town of Stantonsburg, NC	RQ	177	0	0	0
6	Town of Stantonsburg, NC	RQ	177			
7	Town of Winterville, NC	RQ	178	0	0	0
8	Town of Winterville, NC	RQ	178			
9						
10	Other Services					
11	NC Electric Membership Corporation	OS	134			
12	NC Eastern Municipal Power Agency	OS	268			
13	Piedmont EMC	OS	322			
14	Haywood EMC	OS	300			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical 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	Town of Black Creek, NC	OS	293			
2	City of Camden, SC	OS	309			
3	PWC of the City of Fayetteville	OS	324			
4	French Broad EMC	OS	326			
5	Town of Lucama, NC	OS	294			
6	Town of Sharpsburg, NC	OS	296			
7	Town of Stantonsburg, NC	OS	295			
8	Town of Waynesville	OS	321			
9	Industrial Power Generating Corp.	OS	288			
10	The Energy Authority	OS	70			
11	Tennessee Valley Authority	OS	120			
12	North Carolina Municipal PA1	OS	259			
13	Macquarie Energy LLC	OS	342			
14	Other	AD				
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
5,426,920		208,429,026		208,429,026	2
		-255,963		-255,963	3
6,889		241,088		241,088	4
		5,934		5,934	5
205		12,192		12,192	6
					7
					8
	42,419			42,419	9
	-7,812	4,955		-2,857	10
205,434	8,548,101	6,272,792		14,820,893	11
	308,443	70,188		378,631	12
2,181,477	90,082,303	66,168,591		156,250,894	13
	-4,108,803	666,321		-3,442,482	14
18,957,867	715,845,799	574,787,410	0	1,290,633,209	
5,547,604	7,830,000	212,895,170	0	220,725,170	
24,505,471	**723,675,799**	**787,682,580**	**0**	**1,511,358,379**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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.
560,589	16,875,274	17,003,782		33,879,056	1
	341,653	52,603		394,256	2
85,661	2,287,929	2,598,234		4,886,163	3
	-187,512	29,415		-158,097	4
	65,380			65,380	5
	-11,596	7,669		-3,927	6
113,735	7,830,000	4,476,046		12,306,046	7
-499		-26,433		-26,433	8
6,920,383	169,170,010	208,920,708		378,090,718	9
889	-648,350	2,450,982		1,802,632	10
1,115,242	176,910,197	28,921,191		205,831,388	11
-144	-137,532	455,297		317,765	12
7,824,049	266,273,631	236,725,567		502,999,198	13
-13,557	-14,515,726	2,018,562		-12,497,164	14
18,957,867	715,845,799	574,787,410	0	1,290,633,209	
5,547,604	7,830,000	212,895,170	0	220,725,170	
24,505,471	**723,675,799**	**787,682,580**	**0**	**1,511,358,379**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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.
77,844	4,380,723	2,360,017		6,740,740	1
	-73,102	25,870		-47,232	2
	60,473			60,473	3
	-12,954	7,068		-5,886	4
	68,254			68,254	5
	-14,807	6,545		-8,262	6
	174,829			174,829	7
	-25,626	21,053		-4,573	8
					9
					10
354		2,245		2,245	11
		-264		-264	12
		-7		-7	13
		-10		-10	14
18,957,867	715,845,799	574,787,410	0	1,290,633,209	
5,547,604	7,830,000	212,895,170	0	220,725,170	
24,505,471	**723,675,799**	**787,682,580**	**0**	**1,511,358,379**	

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		-1	1
		-9		-9	2
		-84		-84	3
		-22		-22	4
		-1		-1	5
		-1		-1	6
		-1		-1	7
		-4		-4	8
		-1		-1	9
		-34		-34	10
		-10		-10	11
		-3		-3	12
		-32		-32	13
		11,519		11,519	14
18,957,867	715,845,799	574,787,410	0	1,290,633,209	
5,547,604	7,830,000	212,895,170	0	220,725,170	
24,505,471	**723,675,799**	**787,682,580**	**0**	**1,511,358,379**	

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

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: a

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: a

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: a

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: a

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: a

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: a

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: a

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: a

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: a

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 4 Column: a

These sales are Out of Period adjustments related to requirements services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and non-RQ tie to Page 401 line 23 and 24 column b respectively.

Schedule Page: 310.2 Line No.: 6 Column: a

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.: 8 Column: a

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.

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	7,049,768	7,040,867
5	(501) Fuel	328,260,022	338,758,341
6	(502) Steam Expenses	98,801,131	18,814,807
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	17,396	13,057
10	(506) Miscellaneous Steam Power Expenses	12,002,275	9,483,711
11	(507) Rents	360	27,797
12	(509) Allowances	18,471,594	6,626,420
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	464,602,546	380,765,000
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,198,104	5,166,788
16	(511) Maintenance of Structures	11,659,549	9,053,239
17	(512) Maintenance of Boiler Plant	35,112,387	30,666,173
18	(513) Maintenance of Electric Plant	4,379,740	6,347,779
19	(514) Maintenance of Miscellaneous Steam Plant	11,190,404	7,851,475
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	67,540,184	59,085,454
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	532,142,730	439,850,454
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	39,923,359	41,036,569
25	(518) Fuel	187,072,314	205,734,454
26	(519) Coolants and Water	20,912,447	21,251,403
27	(520) Steam Expenses	43,577,463	45,888,808
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,788,939	5,917,431
31	(524) Miscellaneous Nuclear Power Expenses	152,629,681	164,876,067
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	449,904,203	484,704,732
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	75,116,663	75,518,912
36	(529) Maintenance of Structures	15,092,706	16,278,404
37	(530) Maintenance of Reactor Plant Equipment	61,979,194	63,874,892
38	(531) Maintenance of Electric Plant	35,568,051	41,119,415
39	(532) Maintenance of Miscellaneous Nuclear Plant	47,439,313	52,263,913
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	235,195,927	249,055,536
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	685,100,130	733,760,268
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,131,313	2,043,886
45	(536) Water for Power	62,500	62,500
46	(537) Hydraulic Expenses	-357,052	-414,845
47	(538) Electric Expenses	109,004	102,002
48	(539) Miscellaneous Hydraulic Power Generation Expenses	678,683	794,875
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,624,448	2,588,418
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	245,085	245,450
54	(542) Maintenance of Structures	187,001	256,607
55	(543) Maintenance of Reservoirs, Dams, and Waterways	970,911	1,333,948
56	(544) Maintenance of Electric Plant	441,833	707,046
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,668,204	1,831,372
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,513,034	4,374,423
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	6,137,482	6,962,841

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	7,044,410	3,451,442
63	(547) Fuel	899,557,250	710,918,033
64	(548) Generation Expenses	3,422,683	3,139,556
65	(549) Miscellaneous Other Power Generation Expenses	15,412,682	14,091,328
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	925,437,025	731,600,359
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	6,901,548	6,820,301
70	(552) Maintenance of Structures	6,485,683	4,983,289
71	(553) Maintenance of Generating and Electric Plant	25,863,606	16,360,833
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	12,215,247	15,909,903
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	51,466,084	44,074,326
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	976,903,109	775,674,685
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	707,268,038	531,947,253
77	(556) System Control and Load Dispatching	1,738,960	1,577,306
78	(557) Other Expenses	-232,602,079	-89,054,991
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	476,404,919	444,469,568
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,676,688,370	2,400,717,816
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	38,741	21,353
84			
85	(561.1) Load Dispatch-Reliability	2,109,710	2,913,513
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,450,505	2,122,232
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,008,598	898,414
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	281,847	304,130
90	(561.6) Transmission Service Studies	95,000	124
91	(561.7) Generation Interconnection Studies	-70,868	204,069
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,292,946	1,149,024
94	(563) Overhead Lines Expenses	870,995	910,085
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		304
97	(566) Miscellaneous Transmission Expenses	6,829,258	7,808,472
98	(567) Rents	2,901,930	3,082,952
99	TOTAL Operation (Enter Total of lines 83 thru 98)	17,808,662	19,414,672
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	1,339,981	1,628,827
103	(569.1) Maintenance of Computer Hardware	11	3,908
104	(569.2) Maintenance of Computer Software	3,043,183	1,906,119
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,068,225	4,058,579
108	(571) Maintenance of Overhead Lines	12,479,175	11,760,895
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	96,575	36,342
111	TOTAL Maintenance (Total of lines 101 thru 110)	21,027,150	19,394,670
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	38,835,812	38,809,342

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	696,545	466,256
135	(581) Load Dispatching	4,689,874	4,189,184
136	(582) Station Expenses	851,607	1,255,294
137	(583) Overhead Line Expenses	1,879,064	784,874
138	(584) Underground Line Expenses	4,881,127	4,512,350
139	(585) Street Lighting and Signal System Expenses	8,088	7,964
140	(586) Meter Expenses	6,038,529	8,320,395
141	(587) Customer Installations Expenses	5,461,524	3,301,211
142	(588) Miscellaneous Expenses	28,453,526	31,050,172
143	(589) Rents	2,489,215	4,120,922
144	TOTAL Operation (Enter Total of lines 134 thru 143)	55,449,099	58,008,622
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	426,045	12,553
147	(591) Maintenance of Structures	887,430	17,474
148	(592) Maintenance of Station Equipment	2,084,060	3,185,541
149	(593) Maintenance of Overhead Lines	121,847,376	77,989,270
150	(594) Maintenance of Underground Lines	8,095,371	4,550,204
151	(595) Maintenance of Line Transformers	1,100,853	751,963
152	(596) Maintenance of Street Lighting and Signal Systems	8,256,330	7,789,248
153	(597) Maintenance of Meters	1,581,599	1,638,226
154	(598) Maintenance of Miscellaneous Distribution Plant	317,018	-444,674
155	TOTAL Maintenance (Total of lines 146 thru 154)	144,596,082	95,489,805
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	200,045,181	153,498,427
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	59,759	207,031
160	(902) Meter Reading Expenses	5,525,904	5,399,741
161	(903) Customer Records and Collection Expenses	39,373,362	33,941,775
162	(904) Uncollectible Accounts	10,008,548	6,504,470
163	(905) Miscellaneous Customer Accounts Expenses	1,116,785	923,578
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	56,084,358	46,976,595

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	6,477	217
169	(909) Informational and Instructional Expenses	67,011	52,532
170	(910) Miscellaneous Customer Service and Informational Expenses	3,512,540	4,029,991
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	3,586,028	4,082,740
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	10,582	522
175	(912) Demonstrating and Selling Expenses	7,521,391	5,721,905
176	(913) Advertising Expenses	217,839	397,975
177	(916) Miscellaneous Sales Expenses	124,415	87,106
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	7,874,227	6,207,508
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	134,784,940	81,825,259
182	(921) Office Supplies and Expenses	54,554,016	52,335,065
183	(Less) (922) Administrative Expenses Transferred-Credit	-3,396	-6,054
184	(923) Outside Services Employed	53,579,046	58,130,801
185	(924) Property Insurance	-774,442	7,696,580
186	(925) Injuries and Damages	6,373,182	10,215,504
187	(926) Employee Pensions and Benefits	115,350,507	90,966,041
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,596,196	7,127,626
190	(929) (Less) Duplicate Charges-Cr.	3,699,903	5,183,862
191	(930.1) General Advertising Expenses	3,591,669	3,368,011
192	(930.2) Miscellaneous General Expenses	-19,847,613	-26,725,134
193	(931) Rents	30,243,444	33,934,039
194	TOTAL Operation (Enter Total of lines 181 thru 193)	382,754,438	313,695,984
195	Maintenance		
196	(935) Maintenance of General Plant	684,263	757,109
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	383,438,701	314,453,093
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,366,552,677	2,964,745,521

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

Accounts 501007, 501008, and 501009 for Beneficial Reuse in the amount of $7,051,178.64 are excluded from fuel totals allocated by plant on Form 1 pages 402 and 403.

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

Accounts 501007, 501008, and 501009 for Beneficial Reuse in the amount of $32,534,556 are excluded from fuel totals allocated by plant on Form 1 pages 402 and 403.

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	1529 Properties LLC	LU	1.00000	0.00000	0.00000	0.00000
2	2315 Atlantic Ave Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	ABCZ Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Adnan Nasir	LU	1.00000	0.00000	0.00000	0.00000
5	Adventure Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Albert Adcock	LU	1.00000	0.00000	0.00000	0.00000
7	Albertson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Alice Rosser	LU	1.00000	0.00000	0.00000	0.00000
9	Alvin Easton	LU	1.00000	0.00000	0.00000	0.00000
10	AM Best Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Ambient Advisory Services INC	LU	1.00000	0.00000	0.00000	0.00000
12	Amy Underwood	LU	1.00000	0.00000	0.00000	0.00000
13	Anderson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Andrew Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)	Average Monthly CP Demand (f)
1	Angier Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Arba Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Archer Daniels	LU	1.00000	0.00000	0.00000	0.00000
4	Arden Solar	LU	1.00000	0.00000	0.00000	0.00000
5	Argand Rooftop 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Argand Rooftop 3 LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Argand Rooftop 4 LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Argand SPP2 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Aspen Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Atkinson Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Axiom Environmental INC	LU	1.00000	0.00000	0.00000	0.00000
12	B & K Timber LLC	LU	1.00000	0.00000	0.00000	0.00000
13	B.V. Hedrick Gravel & Sand Co	LU	1.00000	0.00000	0.00000	0.00000
14	Balsam Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Baltimore Church	LU	1.00000	0.00000	0.00000	0.00000
2	Barkley-Sexton Energy LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Barry Estes	LU	1.00000	0.00000	0.00000	0.00000
4	Battye Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Bayer Cropscience LP	LU	1.00000	0.00000	0.00000	0.00000
6	Bearford Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Beaufort Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Bertram Kalet	LU	1.00000	0.00000	0.00000	0.00000
9	Beulaville Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	BGE Carolina Sunsense I LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Billy Moon	LU	1.00000	0.00000	0.00000	0.00000
12	Biltmore Natural Resources INC	LU	1.00000	0.00000	0.00000	0.00000
13	Biscoe Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Bizzell Church Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Bizzell Church Solar 2	LU	1.00000	0.00000	0.00000	0.00000
2	Black Creek	LU	1.00000	0.00000	0.00000	0.00000
3	Bladenboro Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Bladenboro Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Blueberry One	LU	1.00000	0.00000	0.00000	0.00000
6	Boaz Farm	LU	1.00000	0.00000	0.00000	0.00000
7	Bolton Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Boone Guyton	LU	1.00000	0.00000	0.00000	0.00000
9	Brandon Laroque	LU	1.00000	0.00000	0.00000	0.00000
10	BRE NC Solar 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Brenda Currin	LU	1.00000	0.00000	0.00000	0.00000
12	Broadway Solar	LU	1.00000	0.00000	0.00000	0.00000
13	Brooks Energy	LU	1.00000	0.00000	0.00000	0.00000
14	Bruce Ford	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Bruce J Rakay	LU	1.00000	0.00000	0.00000	0.00000
2	Buncombe County Landfill	LU	1.00000	0.00000	0.00000	0.00000
3	Bunn Level Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	C II METHANE MANAGEMENT IV LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Camp Rockmont for Boys INC	LU	1.00000	0.00000	0.00000	0.00000
6	Candace Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Carolina Solar Energy NCSU	LU	1.00000	0.00000	0.00000	0.00000
8	Carolina Solar Energy PCSP1	LU	1.00000	0.00000	0.00000	0.00000
9	Carolina Solar Energy-EMJ	LU	1.00000	0.00000	0.00000	0.00000
10	Carolina Tractor & Equipment Co	LU	1.00000	0.00000	0.00000	0.00000
11	Castalia Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Catherine Willis	LU	1.00000	0.00000	0.00000	0.00000
13	CB Bladen Solar	LU	1.00000	0.00000	0.00000	0.00000
14	CBC Alternative Energy LLC (NEW)	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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(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	CBC Alternative Energy LLC (OLD)	LU	1.00000	0.00000	0.00000	0.00000
2	Cedar Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Chadbourn Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Charles Lewis	LU	1.00000	0.00000	0.00000	0.00000
5	Chauncey Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Chei Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Choco Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Chocowinity Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Christiansted Port Terminal Corp.	LU	1.00000	0.00000	0.00000	0.00000
10	Cirrus Solar	LU	1.00000	0.00000	0.00000	0.00000
11	City of Raleigh Parks Recreation Depar	LU	1.00000	0.00000	0.00000	0.00000
12	Clara Reed	LU	1.00000	0.00000	0.00000	0.00000
13	Clipperton Holdings	LU	1.00000	0.00000	0.00000	0.00000
14	Coats Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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1	Cohen Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
2	Corc Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Cornwall Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Cotten Farm	LU	1.00000	0.00000	0.00000	0.00000
5	Covey Run Apartments LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Cox Lake Hydro Electric	LU	1.00000	0.00000	0.00000	0.00000
7	CP Energy Marketing (US) Inc. - Roxbo	LU	1.00000	0.00000	0.00000	0.00000
8	CP Energy Marketing (US) Inc. - South	LU	1.00000	0.00000	0.00000	0.00000
9	CPI Roxboro	LU	1.00000	0.00000	0.00000	0.00000
10	CPI Southport	LU	1.00000	0.00000	0.00000	0.00000
11	Craig Eury	LU	1.00000	0.00000	0.00000	0.00000
12	Craven County Wood Energy LP	LU	1.00000	0.00000	0.00000	0.00000
13	Creech Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Crestwood Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Crockett Farm	LU	1.00000	0.00000	0.00000	0.00000
2	Currin Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Custom Packaging Inc	LU	1.00000	0.00000	0.00000	0.00000
4	Darlington Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	David Tobin	LU	1.00000	0.00000	0.00000	0.00000
6	Daystar Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Debra Bapat	LU	1.00000	0.00000	0.00000	0.00000
8	Deep Branch Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Deep River Hydro	LU	1.00000	0.00000	0.00000	0.00000
10	Delco Farm	LU	1.00000	0.00000	0.00000	0.00000
11	Deltec Homes Inc	LU	1.00000	0.00000	0.00000	0.00000
12	Dement Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Dessie Solar Center	LU	1.00000	0.00000	0.00000	0.00000
14	DRPFC I LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.

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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.

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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	Dunn Solar	LU	1.00000	0.00000	0.00000	0.00000
2	Duplin Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Duplin Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
4	East Wayne Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Easters Holdings LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Eastover Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Elm Solar	LU	1.00000	0.00000	0.00000	0.00000
8	EnergyXchange INC	LU	1.00000	0.00000	0.00000	0.00000
9	Environmental Resources	LU	1.00000	0.00000	0.00000	0.00000
10	Erwin Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	ESA Four Oaks	LU	1.00000	0.00000	0.00000	0.00000
12	ESA NC Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
13	ESA Newton Grove 1 NC LLC	LU	1.00000	0.00000	0.00000	0.00000
14	ESA Princeton NC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	ESA RENEWABLES III LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Eva Anderson (James Anderson Barn)	LU	1.00000	0.00000	0.00000	0.00000
3	Eva Anderson (James Anderson House)	LU	1.00000	0.00000	0.00000	0.00000
4	EWP LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Exhibit Court Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Exum Farm Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	F & D Huebner LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Faison Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Farrington Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Ferguson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	First Christian Church	LU	1.00000	0.00000	0.00000	0.00000
12	First Citizens Bank & Trust Co 1.14MW	LU	1.00000	0.00000	0.00000	0.00000
13	First Citizens Bank & Trust Co 566KW	LU	1.00000	0.00000	0.00000	0.00000
14	Floyd Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	FLS Owner 80 LLC	LU	1.00000	0.00000	0.00000	0.00000
2	FLS Owner II LLC	LU	1.00000	0.00000	0.00000	0.00000
3	FLS Solar 10 LLC	LU	1.00000	0.00000	0.00000	0.00000
4	FLS Solar 100 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	FLS Solar 110 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	FLS Solar 170 LLC	LU	1.00000	0.00000	0.00000	0.00000
7	FLS Solar 20 LLC - Chatham (FLS Owner	LU	1.00000	0.00000	0.00000	0.00000
8	FLS Solar 20 LLC (Greensquare)	LU	1.00000	0.00000	0.00000	0.00000
9	FLS Solar 20 LLC - HCC	LU	1.00000	0.00000	0.00000	0.00000
10	FLS Solar 200 LLC	LU	1.00000	0.00000	0.00000	0.00000
11	FLS Solar 230 LLC - Warren Place	LU	1.00000	0.00000	0.00000	0.00000
12	FLS Solar 260 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	FLS YK Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Foxfire Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Franklin Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Franklin Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Franklinton Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Fremont Farms LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Fresh Air Energy - Carter	LU	1.00000	0.00000	0.00000	0.00000
6	Fresh Air Energy - Langley	LU	1.00000	0.00000	0.00000	0.00000
7	Fresh Air Energy - Pecan	LU	1.00000	0.00000	0.00000	0.00000
8	Fresh Air Energy XXXI - Little River	LU	1.00000	0.00000	0.00000	0.00000
9	Fresh Air Thornton (Fresh Air XVI LLC)	LU	1.00000	0.00000	0.00000	0.00000
10	Fuquay Farms LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Gainey Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Garrell Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
13	Gary Shaver	LU	1.00000	0.00000	0.00000	0.00000
14	Gary Spodnick	LU	1.00000	0.00000	0.00000	0.00000
	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	Gaylond Owens	LU	1.00000	0.00000	0.00000	0.00000
2	Gene Rainey	LU	1.00000	0.00000	0.00000	0.00000
3	Glen Raven Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Gordon Koncal	LU	1.00000	0.00000	0.00000	0.00000
5	Granville Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Greenfield Power GTP One LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Gregory Poole Equip Co	LU	1.00000	0.00000	0.00000	0.00000
8	Happy Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Harrell's Hill Solar	LU	1.00000	0.00000	0.00000	0.00000
10	Harvest Beulaville	LU	1.00000	0.00000	0.00000	0.00000
11	Haywood Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
12	HCE Johnston I LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Hector Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Hessler 115KW	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Hessler 153KW	LU	1.00000	0.00000	0.00000	0.00000
2	Hew Fulton Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Highland Community Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Highland Craftsmen INC	LU	1.00000	0.00000	0.00000	0.00000
5	Highland Solar Center	LU	1.00000	0.00000	0.00000	0.00000
6	Highwater Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Holstein Holdings	LU	1.00000	0.00000	0.00000	0.00000
8	Hood Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Howard Plemmons	LU	1.00000	0.00000	0.00000	0.00000
10	Hydrodyne-High Falls	LU	1.00000	0.00000	0.00000	0.00000
11	Hydrodyne-Little River	LU	1.00000	0.00000	0.00000	0.00000
12	Ideal Fastner Corp	LU	1.00000	0.00000	0.00000	0.00000
13	Ingenco Renewables	LU	1.00000	0.00000	0.00000	0.00000
14	Ingenco Wholesale	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Innovative Solar 10	LU	1.00000	0.00000	0.00000	0.00000
2	Innovative Solar 31 LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Innovative Solar 35 LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Innovative Solar 37 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Innovative Solar 42	LU	1.00000	0.00000	0.00000	0.00000
6	Innovative Solar 43 LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Innovative Solar 44 LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Innovative Solar 46 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Innovative Solar 47 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Innovative Solar 48 LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Innovative Solar 59 LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Innovative Solar 6	LU	1.00000	0.00000	0.00000	0.00000
13	Innovative Solar 60 LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Innovative Solar 63	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.

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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	Innovative Solar 64 LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Innovative Solar 65 LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Innovative Solar6 P1	LU	1.00000	0.00000	0.00000	0.00000
4	Innovative Solar6 P2	LU	1.00000	0.00000	0.00000	0.00000
5	International Paper	LU	1.00000	0.00000	0.00000	0.00000
6	J Godwin (John)	LU	1.00000	0.00000	0.00000	0.00000
7	Jack Bennett	LU	1.00000	0.00000	0.00000	0.00000
8	Jackson & Sons Inc	LU	1.00000	0.00000	0.00000	0.00000
9	James Hubbell	LU	1.00000	0.00000	0.00000	0.00000
10	James Thorpe	LU	1.00000	0.00000	0.00000	0.00000
11	James Young (Asheville Alternative)	LU	1.00000	0.00000	0.00000	0.00000
12	James Young (Asheville Alt Energy)	LU	1.00000	0.00000	0.00000	0.00000
13	Janet Dektor	LU	1.00000	0.00000	0.00000	0.00000
14	Jason Hibbets	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Jerry Sullivan	LU	1.00000	0.00000	0.00000	0.00000
2	Jessica Larsen (Chris Larsen)	LU	1.00000	0.00000	0.00000	0.00000
3	John Hollingsworth	LU	1.00000	0.00000	0.00000	0.00000
4	John McDermott	LU	1.00000	0.00000	0.00000	0.00000
5	John Reese	LU	1.00000	0.00000	0.00000	0.00000
6	Johnson Breeders	LU	1.00000	0.00000	0.00000	0.00000
7	Jordan Hydroelectric LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Joseph Callahan	LU	1.00000	0.00000	0.00000	0.00000
9	Joseph Ponzi	LU	1.00000	0.00000	0.00000	0.00000
10	JT Hobby & Sons Inc.	LU	1.00000	0.00000	0.00000	0.00000
11	K & HB Enterprises LLC - Waynesville	LU	1.00000	0.00000	0.00000	0.00000
12	K & HB Enterprises LLC - Asheville	LU	1.00000	0.00000	0.00000	0.00000
13	Karen Mallam	LU	1.00000	0.00000	0.00000	0.00000
14	Kathy Hansinger	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Keen Farm	LU	1.00000	0.00000	0.00000	0.00000
2	Kelly Daiker	LU	1.00000	0.00000	0.00000	0.00000
3	Kenansville Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Kenansville Solar Farm LLC (Heelstone	LU	1.00000	0.00000	0.00000	0.00000
5	Kenansville Solar LLC (FLS Energy)	LU	1.00000	0.00000	0.00000	0.00000
6	Kennedy Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Kenneth Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Kinston Davis Farm	LU	1.00000	0.00000	0.00000	0.00000
9	Kinston Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Kirkwall Holdings LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Kojak farm	LU	1.00000	0.00000	0.00000	0.00000
12	Kristen Blackley	LU	1.00000	0.00000	0.00000	0.00000
13	L&D Incorporated	LU	1.00000	0.00000	0.00000	0.00000
14	L&S Waterpower	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Lake Upchurch Power Inc.	LU	1.00000	0.00000	0.00000	0.00000
2	Land of the Sky MT (Eden Solar/Innovat	LU	1.00000	0.00000	0.00000	0.00000
3	Laney Development Inc	LU	1.00000	0.00000	0.00000	0.00000
4	Lang Solar	LU	1.00000	0.00000	0.00000	0.00000
5	Langdon Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Lanier Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Laurinburg Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Lea Romano	LU	1.00000	0.00000	0.00000	0.00000
9	Lenior Farm 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Lenior Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Leonard Bernstein	LU	1.00000	0.00000	0.00000	0.00000
12	Lewis Rothlein	LU	1.00000	0.00000	0.00000	0.00000
13	Lillington Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Linda Sweeney	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Logan Trading Co Inc.	LU	1.00000	0.00000	0.00000	0.00000
2	Lumberton Power	LU	1.00000	0.00000	0.00000	0.00000
3	M B Haynes Corporation 12KW	LU	1.00000	0.00000	0.00000	0.00000
4	M B Haynes Corporation 24KW	LU	1.00000	0.00000	0.00000	0.00000
5	M Stone (Mike)	LU	1.00000	0.00000	0.00000	0.00000
6	Madison Hydro Partners	LU	1.00000	0.00000	0.00000	0.00000
7	Mahadev Enterprises LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Manway Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Margaret Hayes	LU	1.00000	0.00000	0.00000	0.00000
10	Mark Parker	LU	1.00000	0.00000	0.00000	0.00000
11	Marshall's Locksmith Services Inc	LU	1.00000	0.00000	0.00000	0.00000
12	Martin Creek Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Maxton Solar 1	LU	1.00000	0.00000	0.00000	0.00000
14	McCallum Farm	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
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1	McGoogan Farm	LU	1.00000	0.00000	0.00000	0.00000
2	McKenzie Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	MDK Cornerstone LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Melinda Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Meriwether Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Metropolitan Sewerage	LU	1.00000	0.00000	0.00000	0.00000
7	Mile Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Mill Pond Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
9	Mills Anson Farm	LU	1.00000	0.00000	0.00000	0.00000
10	Moncure Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Montgomery Solar	LU	1.00000	0.00000	0.00000	0.00000
12	Moorings Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Moorings Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Morgan Farm	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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(Including power exchanges)

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1	Mount Olive Solar	LU	1.00000	0.00000	0.00000	0.00000
2	MP Wayne County Landfill	LU	1.00000	0.00000	0.00000	0.00000
3	Mt Olive Farm	LU	1.00000	0.00000	0.00000	0.00000
4	Mt Olive Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Mt Olive Solar 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Munich Motors INC	LU	1.00000	0.00000	0.00000	0.00000
7	Murdock Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Nash 58 Farm	LU	1.00000	0.00000	0.00000	0.00000
9	Nash 64 Farm	LU	1.00000	0.00000	0.00000	0.00000
10	Nash 97 Solar	LU	1.00000	0.00000	0.00000	0.00000
11	Nashville Farms LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Nathan Conroy	LU	1.00000	0.00000	0.00000	0.00000
13	NC State Museum of Nat Science	LU	1.00000	0.00000	0.00000	0.00000
14	NCEMC - Ajax	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NCEMC - Bear Creek Solar	LU	1.00000	0.00000	0.00000	0.00000
2	NCEMC - Flint Solar	LU	1.00000	0.00000	0.00000	0.00000
3	NCEMC - Jersey Holdings Solar	LU	1.00000	0.00000	0.00000	0.00000
4	NCEMC - Long Henry Solar	LU	1.00000	0.00000	0.00000	0.00000
5	NCEMC - Revolution Dial Road	LU	1.00000	0.00000	0.00000	0.00000
6	NCEMC - Revolution Ezzel Road	LU	1.00000	0.00000	0.00000	0.00000
7	NCEMC - Robeson Landfill (Phase 1)	LU	1.00000	0.00000	0.00000	0.00000
8	NCEMC - Robeson Landfill (Phase 2)	LU	1.00000	0.00000	0.00000	0.00000
9	NCEMC - Rosewood Solar	LU	1.00000	0.00000	0.00000	0.00000
10	NCEMC - Ruskin Solar	LU	1.00000	0.00000	0.00000	0.00000
11	NCEMC - Scarlett Solar	LU	1.00000	0.00000	0.00000	0.00000
12	NCEMC - Snow Camp Solar	LU	1.00000	0.00000	0.00000	0.00000
13	NCEMC - Storm Hog Partners	LU	1.00000	0.00000	0.00000	0.00000
14	NCEMC - Storm Hog Partners 2	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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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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.

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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	NCEMC - Sunny Point	LU	1.00000	0.00000	0.00000	0.00000
2	NCEMC - Viper Solar	LU	1.00000	0.00000	0.00000	0.00000
3	NCEMPA	LU	1.00000	0.00000	0.00000	0.00000
4	Neuse River Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
5	New Bern Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Nitro Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	North Carolina Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
8	North Carolina Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
9	North Carolina Solar III Lessee LLC	LU	1.00000	0.00000	0.00000	0.00000
10	North Nash Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Oakboro Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Old Webbs Mill Hydro LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Old Wire Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Onslow Power Producers LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	P K Ventures Inc	LU	1.00000	0.00000	0.00000	0.00000
2	Pate Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	PCIP Solar Lessee LLC	LU	1.00000	0.00000	0.00000	0.00000
4	PCSP3 Airport LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Perkins Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Pikeville Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Pinedale Springs	LU	1.00000	0.00000	0.00000	0.00000
8	Pohoja Corporation (Kenneth Sheffield)	LU	1.00000	0.00000	0.00000	0.00000
9	Pollocksville Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Porter Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Prestage Agenergy NC	LU	1.00000	0.00000	0.00000	0.00000
12	Prestage Farms Inc.	LU	1.00000	0.00000	0.00000	0.00000
13	Progress Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Progress Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Progress Solar III LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Quarters LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Quincy Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Raeford Farm	LU	1.00000	0.00000	0.00000	0.00000
5	Railroad Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Railroad Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Railroad Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Red Hill Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Red Oak Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Red Toad A Powatan Road LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Red Toad II LLC	LU	1.00000	0.00000	0.00000	0.00000
12	REI 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Renewable Power LLC (Foodlion)	LU	1.00000	0.00000	0.00000	0.00000
14	RES AG DM 2-1 LLC (RES Agriculture NC	LU	1.00000	0.00000	0.00000	0.00000
	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	RES AG DM 4-3 LLC (RES Agriculture NC	LU	1.00000	0.00000	0.00000	0.00000
2	Riding Partners Bio	LU	1.00000	0.00000	0.00000	0.00000
3	Riding Partners INC	LU	1.00000	0.00000	0.00000	0.00000
4	Riding Partners INC #2	LU	1.00000	0.00000	0.00000	0.00000
5	Riding Partners INC #3	LU	1.00000	0.00000	0.00000	0.00000
6	Robert & Phyllis Wooten	LU	1.00000	0.00000	0.00000	0.00000
7	Robert Beatty	LU	1.00000	0.00000	0.00000	0.00000
8	Robert Dick	LU	1.00000	0.00000	0.00000	0.00000
9	Robert Harris	LU	1.00000	0.00000	0.00000	0.00000
10	Robert Hicks	LU	1.00000	0.00000	0.00000	0.00000
11	Robert Wooten	LU	1.00000	0.00000	0.00000	0.00000
12	Rock Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Rockingham Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Rocky Mount Mills	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Rocky River Hydro LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Rose Hill Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Roxboro Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Roxboro Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
5	Royal Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Sam Rogers	LU	1.00000	0.00000	0.00000	0.00000
7	Samarcand Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Sampson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Sandy Cross Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Sarah Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	SAS - 1200KW	LU	1.00000	0.00000	0.00000	0.00000
12	SAS Institute - Building G	LU	1.00000	0.00000	0.00000	0.00000
13	SAS Institute - Building T	LU	1.00000	0.00000	0.00000	0.00000
14	SAS Institute Inc	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Scott Shackleton	LU	1.00000	0.00000	0.00000	0.00000
2	Sedberry Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	SEGY LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Selma Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
5	Shannon Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Siler 421 Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	SMB Holding 10 LLC	LU	1.00000	0.00000	0.00000	0.00000
8	SMB Holdings 5 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Snow Hill Solar 2	LU	1.00000	0.00000	0.00000	0.00000
10	Sol Sencia Ventures LLC (Paul Kazmer)	LU	1.00000	0.00000	0.00000	0.00000
11	Solar 55 LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Solarworks RCC LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Soluga Farm I LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Soluga Farm II LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Soluga Farm III LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Sonne One LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Soul City Solar	LU	1.00000	0.00000	0.00000	0.00000
4	South Atlantic Services	LU	1.00000	0.00000	0.00000	0.00000
5	South Louisburg Solar	LU	1.00000	0.00000	0.00000	0.00000
6	South Robeson Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Southeastern Freight Lines	LU	1.00000	0.00000	0.00000	0.00000
8	Southerland Farms	LU	1.00000	0.00000	0.00000	0.00000
9	Spicewood Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
10	Spring Valley Solar 2	LU	1.00000	0.00000	0.00000	0.00000
11	St. Pauls Solar 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
12	St. Pauls Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Stagecoach Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Stainback Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Steve Zarnowski (FLAT CREEK)	LU	1.00000	0.00000	0.00000	0.00000
2	Stone Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Strata Fund 11 Lessee LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Sumter Heat & Power LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Sun Devil Solar	LU	1.00000	0.00000	0.00000	0.00000
6	SunE Bearpond Lessee	LU	1.00000	0.00000	0.00000	0.00000
7	SunE Graham Lessee	LU	1.00000	0.00000	0.00000	0.00000
8	SunE NC Progress LLC	LU	1.00000	0.00000	0.00000	0.00000
9	SunE Shankle Lessee	LU	1.00000	0.00000	0.00000	0.00000
10	Sunenergy1-Asheville LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Sunfish Solar	LU	1.00000	0.00000	0.00000	0.00000
12	Sunstruck Energy LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Sweetgum Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Tart Farm	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Thaddeus Burgess Trust	LU	1.00000	0.00000	0.00000	0.00000
2	The Big Chicken LLC	LU	1.00000	0.00000	0.00000	0.00000
3	The N C Growers Assoc Inc	LU	1.00000	0.00000	0.00000	0.00000
4	The Rock Solar Energy Plant LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Tony Gaddis	LU	1.00000	0.00000	0.00000	0.00000
6	Town of Warsaw Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Town Square West	LU	1.00000	0.00000	0.00000	0.00000
8	Tracy Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Tria Cline	LU	1.00000	0.00000	0.00000	0.00000
10	Tryon Road INC	LU	1.00000	0.00000	0.00000	0.00000
11	Turkey Branch Solar (FLS 2014 SOLAR A)	LU	1.00000	0.00000	0.00000	0.00000
12	TWE Chocowinity	LU	1.00000	0.00000	0.00000	0.00000
13	TWE Kinston Solar	LU	1.00000	0.00000	0.00000	0.00000
14	TWE Laurinburg	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	TWE New Bern Solar	LU	1.00000	0.00000	0.00000	0.00000
2	US Dept of Commerce NOAA (Randy Grady)	LU	1.00000	0.00000	0.00000	0.00000
3	Uwharrie Mountain Renewables	LU	1.00000	0.00000	0.00000	0.00000
4	Vance Solar 1	LU	1.00000	0.00000	0.00000	0.00000
5	Vandy LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Vickers Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
7	Vicksburg Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	W.E. Partners IV LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Wadesboro Farm	LU	1.00000	0.00000	0.00000	0.00000
10	Wadesboro Farm 2	LU	1.00000	0.00000	0.00000	0.00000
11	Wadesboro Farm 3	LU	1.00000	0.00000	0.00000	0.00000
12	Wagstaff Farm 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Wake Tech Innovations Inc	LU	1.00000	0.00000	0.00000	0.00000
14	Wallace Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Warren Wilson College	LU	1.00000	0.00000	0.00000	0.00000
2	Warrenton Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Warsaw Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Warsaw Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Watts Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Wayne County Public Schools	LU	1.00000	0.00000	0.00000	0.00000
7	Wayne Hilbert	LU	1.00000	0.00000	0.00000	0.00000
8	Wayne Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Wayne Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Wayne Solar III LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Wellons Farm	LU	1.00000	0.00000	0.00000	0.00000
12	West Siler Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Westgate Auto Group LLC	LU	1.00000	0.00000	0.00000	0.00000
14	William Kelly	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Wilson Farm 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Woodland Church Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Wortham Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Yanceyville Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Yanceyville Farm 3	LU	1.00000	0.00000	0.00000	0.00000
6	Yanceyville Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	ZV Solar 1	LU	1.00000	0.00000	0.00000	0.00000
8	ZV Solar 2	LU	1.00000	0.00000	0.00000	0.00000
9	ZV Solar 3	LU	1.00000	0.00000	0.00000	0.00000
10	Barker Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Bladen Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Broadridge Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Bullock Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Freedom Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Henry Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Innovative Solar 55 LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Shoe Creek Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Wakefield Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	MDK Cornerstone LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Warren Wilson College	LU	1.00000	0.00000	0.00000	0.00000
7	ABD Farm Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Wadesboro Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Wadford Storage LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Pollocksville Solar	LU	1.00000	0.00000	0.00000	0.00000
11	Railroad Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
12	Red Oak Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
13	NCEMC - Bondi Solar	LU	1.00000	0.00000	0.00000	0.00000
14	NUGS Write-Off	LU	1.00000	0.00000	0.00000	0.00000
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Bearford Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Holstein Holdings	LU	1.00000	0.00000	0.00000	0.00000
3	Bayboro Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
4	Sneads Grove Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Wadford Storage	LU	1.00000	0.00000	0.00000	0.00000
6	NCEMC - Strider Solar	LU	1.00000	0.00000	0.00000	0.00000
7	DSM Nutritional	LU	1.00000	0.00000	0.00000	0.00000
8	Cougar Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Hanover Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Ed's Gun Shop	LU	1.00000	0.00000	0.00000	0.00000
11	Kalish Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
12	Walter Henry Bundy	LU	1.00000	0.00000	0.00000	0.00000
13	Kelly Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Mustang Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Sadiebrook Solar	LU	1.00000	0.00000	0.00000	0.00000
2	Heedeh Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Bladenboro Farm 2	LU	1.00000	0.00000	0.00000	0.00000
4	County Home	LU	1.00000	0.00000	0.00000	0.00000
5	ESA Church Road	LU	1.00000	0.00000	0.00000	0.00000
6	Soluga Farms IV LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Trent River Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Lane Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	A&G/Kitty hawk Solar	LU	1.00000	0.00000	0.00000	0.00000
10	Arthur Solar	LU	1.00000	0.00000	0.00000	0.00000
11	NCEMC - Copperfield Solar	LU	1.00000	0.00000	0.00000	0.00000
12	NCEMC - Hopewell Friends Solar	LU	1.00000	0.00000	0.00000	0.00000
13	NCEMC - Morning View Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Broad River Energy, LLC	LU	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Broad River Energy, LLC	AD	1			
2	City of Fayetteville (Butler Warner)	OS				
3	City of Fayetteville (Butler Warner)	AD				
4	Southern Power Co	LU	7			
5	Southern Power Co	AD	7			
6	PJM Settlements, Inc	OS	188			
7	PJM Settlements, Inc	AD	188			
8	Haywood Electric Membership Corp	LF	180			
9	Haywood Electric Membership Corp	AD	180			
10	NC Electric Membership Corp	LF	182			
11	NC Electric Membership Corp	AD	182			
12	Duke Energy Carolinas, LLC	OS	190			
13	Duke Energy Carolinas, LLC	AD	190			
14	Duke Energy Carolinas, LLC	OS	45			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Duke Energy Carolinas, LLC	OS	4			
2	Virginia Electric and Power Company	OS	196			
3	Town of Black Creek	EX				
4	Town of Lucama	EX				
5	Town of Sharpsburg	EX				
6	Town of Stantonsburg	EX				
7	Town of Waynesville	EX				
8	Town of Winterville	EX				
9	NC Electric Membership Corp	EX				
10	Walter Henry Bundy	LU				
11	DSM Nutritional	LU				
12	Freedom Solar	LU				
13	Net Metering					
14	Smurfit Stone Container					
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				3		3	1
632				48,392		48,392	2
603				37,756		37,756	3
				3		3	4
37				2,831		2,831	5
42				3,200		3,200	6
10,693				710,435		710,435	7
12				825		825	8
15				1,171		1,171	9
8,349				686,084		686,084	10
5				165		165	11
				13		13	12
3,998				328,022		328,022	13
9,354				624,267		624,267	14
10,834,182			109,348,280	597,919,758		707,268,038	

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.
7,448				612,890		612,890	1
3,277				269,856		269,856	2
96				3,218		3,218	3
270				9,179		9,179	4
679				51,968		51,968	5
296				22,701		22,701	6
622				47,650		47,650	7
246				15,408		15,408	8
8,824				589,276		589,276	9
8,951				597,972		597,972	10
6				418		418	11
14				1,091		1,091	12
15				1,172		1,172	13
8,972				598,060		598,060	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7,963				494,751		494,751	1
82				4,938		4,938	2
8				270		270	3
33				2,047		2,047	4
31				1,979		1,979	5
8,980				604,374		604,374	6
26,755				1,786,002		1,786,002	7
8				633		633	8
3,485				287,165		287,165	9
597				45,712		45,712	10
6				202		202	11
2,012				68,326		68,326	12
8,922				524,139		524,139	13
9,355				622,969		622,969	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
9,138				607,799		607,799	1
62,631				3,791,662		3,791,662	2
8,322				683,592		683,592	3
9,477				629,154		629,154	4
9,453				628,413		628,413	5
9,053				600,655		600,655	6
8,783				724,526		724,526	7
				12		12	8
24				1,721		1,721	9
8,497				567,879		567,879	10
2				60		60	11
9,062				749,513		749,513	12
441				34,915		34,915	13
5				180		180	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
6				224		224	1
8,574				577,641		577,641	2
9,497				784,301		784,301	3
10,802				787,063		787,063	4
9				317		317	5
8,792				583,313		583,313	6
83				5,479		5,479	7
763				47,765		47,765	8
331				20,725		20,725	9
310				19,393		19,393	10
3,674				304,716		304,716	11
9				320		320	12
9,279				615,519		615,519	13
4,204				343,579		343,579	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
1,696				129,878		129,878	1
8,971				599,978		599,978	2
9,460				777,934		777,934	3
2				82		82	4
8,452				549,579		549,579	5
8,792				583,659		583,659	6
10,356				688,471		688,471	7
8,610				576,709		576,709	8
632				38,251		38,251	9
8,735				581,409		581,409	10
37				2,330		2,330	11
7				236		236	12
9,812				650,458		650,458	13
9,570				636,735		636,735	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
9,638				640,621		640,621	1
312				25,908		25,908	2
8,785				723,291		723,291	3
9,501				594,775		594,775	4
7				255		255	5
1,102				88,021		88,021	6
							7
							8
326,614				24,813,326		24,813,326	9
438,489				35,338,233		35,338,233	10
6				228		228	11
305,884				15,386,785		15,386,785	12
9,160				610,529		610,529	13
8,683				580,843		580,843	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
8,865				578,059		578,059	1
8,571				538,302		538,302	2
249				19,089		19,089	3
19,331				1,016,948		1,016,948	4
2				65		65	5
9,289				580,288		580,288	6
3				110		110	7
9,281				576,752		576,752	8
1,023				83,254		83,254	9
8,558				567,575		567,575	10
67				2,270		2,270	11
8,764				724,996		724,996	12
8,326				682,657		682,657	13
24				1,513		1,513	14
10,834,182			109,348,280	597,919,758		707,268,038	

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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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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)	
3,570				294,462		294,462	1
8,135				669,304		669,304	2
8,781				719,954		719,954	3
3,715				304,697		304,697	4
15				936		936	5
8,864				732,831		732,831	6
9,207				614,289		614,289	7
6				204		204	8
5				175		175	9
6,376				416,717		416,717	10
7,798				500,957		500,957	11
606				46,383		46,383	12
3,249				269,037		269,037	13
8,905				578,905		578,905	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
1,296				81,168		81,168	1
12				675		675	2
6				344		344	3
939				62,423		62,423	4
627				51,829		51,829	5
9,183				614,016		614,016	6
32				2,025		2,025	7
2,779				180,518		180,518	8
1,327				101,605		101,605	9
180				6,109		6,109	10
13				753		753	11
1,179				40,067		40,067	12
624				21,196		21,196	13
9,083				603,034		603,034	14
10,834,182			109,348,280	597,919,758		707,268,038	

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.
2,285				176,874		176,874	1
129				10,736		10,736	2
596				37,324		37,324	3
6,733				555,232		555,232	4
3,254				270,139		270,139	5
3,620				242,028		242,028	6
93				7,087		7,087	7
347				26,585		26,585	8
							9
6,241				413,429		413,429	10
8,586				571,655		571,655	11
8,783				582,632		582,632	12
68				4,234		4,234	13
9,462				629,410		629,410	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
4,069				335,632		335,632	1
3,259				269,916		269,916	2
9,538				640,119		640,119	3
10,119				630,893		630,893	4
8,586				569,583		569,583	5
9,708				646,913		646,913	6
9,258				616,224		616,224	7
8,507				567,903		567,903	8
8,369				560,846		560,846	9
8,405				693,263		693,263	10
4,437				296,731		296,731	11
6,813				560,675		560,675	12
13				437		437	13
3				88		88	14
10,834,182			109,348,280	597,919,758		707,268,038	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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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5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1				36		36	1
1				22		22	2
534				33,449		33,449	3
5				355		355	4
4,526				346,587		346,587	5
310				19,422		19,422	6
286				17,919		17,919	7
7,165				476,285		476,285	8
8,853				728,919		728,919	9
3,866				240,169		240,169	10
9,313				617,886		617,886	11
3,624				242,635		242,635	12
9,292				581,314		581,314	13
132				8,252		8,252	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
165				12,672		12,672	1
9,249				614,665		614,665	2
49				2,695		2,695	3
2				54		54	4
9,132				610,753		610,753	5
9,916				659,900		659,900	6
28,325				1,521,608		1,521,608	7
9,209				614,805		614,805	8
11				369		369	9
166				13,136		13,136	10
191				15,665		15,665	11
256				19,564		19,564	12
44,828				3,055,474		3,055,474	13
22,854				765,806		765,806	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
2,522				167,474		167,474	1
61,599				3,801,729		3,801,729	2
3,862				241,001		241,001	3
147,484				8,317,027		8,317,027	4
131,957				7,051,083		7,051,083	5
68,612				3,987,695		3,987,695	6
8,201				543,269		543,269	7
142,940				7,714,917		7,714,917	8
72,170				4,126,895		4,126,895	9
8,496				564,027		564,027	10
3,850				240,115		240,115	11
1,431				95,746		95,746	12
4,013				251,632		251,632	13
8,197				545,846		545,846	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
8,422				560,567		560,567	1
9,004				556,438		556,438	2
1,429				96,207		96,207	3
3,279				219,599		219,599	4
707				23,485		23,485	5
13				467		467	6
3				92		92	7
29				1,804		1,804	8
5				179		179	9
3				226		226	10
39				1,325		1,325	11
52				1,738		1,738	12
4				151		151	13
6				208		208	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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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)	
6				243		243	1
5				174		174	2
1				85		85	3
				17		17	4
5				159		159	5
413				13,850		13,850	6
11,129				737,556		737,556	7
1				36		36	8
6				216		216	9
1,566				130,754		130,754	10
33				2,044		2,044	11
33				2,095		2,095	12
12				420		420	13
1				29		29	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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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)	
8,986				597,318		597,318	1
3				92		92	2
3,622				243,679		243,679	3
7,317				603,731		603,731	4
3,561				294,302		294,302	5
9,064				602,748		602,748	6
4,829				322,291		322,291	7
8,690				566,666		566,666	8
3,734				308,047		308,047	9
9,119				607,143		607,143	10
8,813				586,359		586,359	11
6				208		208	12
11				705		705	13
1,494				119,884		119,884	14
10,834,182			109,348,280	597,919,758		707,268,038	

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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
85,569				5,273,207		5,273,207	2
11				873		873	3
9,242				614,854		614,854	4
8,909				592,593		592,593	5
8,953				597,831		597,831	6
4,136				275,859		275,859	7
2				80		80	8
8,320				684,429		684,429	9
8,058				661,807		661,807	10
							11
				19		19	12
9,671				605,868		605,868	13
2				169		169	14
10,834,182			109,348,280	597,919,758		707,268,038	

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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.
55				3,442		3,442	1
132,886				10,179,614		10,179,614	2
14				1,088		1,088	3
32				2,414		2,414	4
							5
3,075				198,331		198,331	6
13				1,003		1,003	7
9,340				617,978		617,978	8
6				193		193	9
5				162		162	10
17				1,267		1,267	11
5,301				438,928		438,928	12
9,344				619,634		619,634	13
8,459				696,432		696,432	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
9,373				619,244		619,244	1
8,071				527,189		527,189	2
				-14		-14	3
8,233				545,403		545,403	4
9,228				578,700		578,700	5
9				325		325	6
8,486				702,154		702,154	7
8,046				507,229		507,229	8
8,694				579,832		579,832	9
5,878				485,223		485,223	10
38,338				2,263,638		2,263,638	11
9,452				588,437		588,437	12
7,801				638,462		638,462	13
9,384				625,533		625,533	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
3,755				249,451		249,451	1
9,809				596,468		596,468	2
9,547				784,018		784,018	3
8,788				722,629		722,629	4
8,212				542,656		542,656	5
5				161		161	6
6,991				465,561		465,561	7
8,712				716,913		716,913	8
7,374				609,096		609,096	9
9,345				622,644		622,644	10
3,778				311,050		311,050	11
				-2		-2	12
1				23		23	13
3,956				223,490		223,490	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
3,927				223,658		223,658	1
9,000				456,426		456,426	2
9,023				483,791		483,791	3
3,937				221,591		221,591	4
470				25,995		25,995	5
2,855				194,336		194,336	6
315				22,678		22,678	7
2,945				161,715		161,715	8
3,899				220,706		220,706	9
3,940				222,028		222,028	10
3,976				224,345		224,345	11
10,853				598,672		598,672	12
697				48,303		48,303	13
826				58,624		58,624	14
10,834,182			109,348,280	597,919,758		707,268,038	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/12/2019	End of 2018/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.
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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.
1,918				112,564		112,564	1
3,820				215,681		215,681	2
259,514				16,444,619		16,444,619	3
1,490				93,314		93,314	4
8,602				705,630		705,630	5
8,083				535,709		535,709	6
3,016				230,905		230,905	7
3,676				303,391		303,391	8
8,652				711,997		711,997	9
9,487				633,368		633,368	10
8,358				543,164		543,164	11
							12
9,738				603,248		603,248	13
7,575				545,978		545,978	14
10,834,182			109,348,280	597,919,758		707,268,038	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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)	
							1
8,595				706,636		706,636	2
1,710				107,086		107,086	3
4,215				322,743		322,743	4
3,648				230,504		230,504	5
10,201				637,220		637,220	6
75				4,774		4,774	7
21				715		715	8
8,543				571,663		571,663	9
7,494				469,985		469,985	10
188				9,901		9,901	11
404				32,156		32,156	12
6,119				504,187		504,187	13
5,725				470,234		470,234	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
5,856				481,626		481,626	1
598				45,804		45,804	2
5,221				345,101		345,101	3
8,790				720,209		720,209	4
8,521				699,986		699,986	5
9,371				772,888		772,888	6
5,842				388,776		388,776	7
8,450				698,368		698,368	8
9,155				577,667		577,667	9
3,964				257,960		257,960	10
554				42,420		42,420	11
							12
142				8,915		8,915	13
							14
10,834,182			109,348,280	597,919,758		707,268,038	

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.
							1
3				110		110	2
7				233		233	3
5				174		174	4
3				99		99	5
3				115		115	6
10				349		349	7
				13		13	8
4				130		130	9
				9		9	10
							11
8,450				697,748		697,748	12
9,374				621,580		621,580	13
							14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
							1
3,574				293,294		293,294	2
8,005				657,853		657,853	3
8,780				552,392		552,392	4
8,761				581,613		581,613	5
6				221		221	6
8,472				701,582		701,582	7
3,928				261,998		261,998	8
1,885				144,350		144,350	9
8,079				538,524		538,524	10
2,027				138,662		138,662	11
							12
							13
398				24,112		24,112	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
1				33		33	1
8,863				589,277		589,277	2
7				246		246	3
8,938				736,250		736,250	4
8,520				696,053		696,053	5
9,719				648,632		648,632	6
15				1,052		1,052	7
13				455		455	8
3,655				300,996		300,996	9
100				5,268		5,268	10
2,294				190,310		190,310	11
581				44,502		44,502	12
9,014				584,900		584,900	13
8,522				555,259		555,259	14
10,834,182			109,348,280	597,919,758		707,268,038	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
9,398				624,891		624,891	1
8,737				581,477		581,477	2
5,312				353,880		353,880	3
3,418				219,735		219,735	4
9,692				647,259		647,259	5
8,590				709,620		709,620	6
2,002				107,766		107,766	7
9,180				570,223		570,223	8
8,502				555,670		555,670	9
9,126				567,842		567,842	10
9,218				570,037		570,037	11
9,225				611,509		611,509	12
7,811				521,900		521,900	13
9,231				443,709		443,709	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
30				1,052		1,052	1
9,450				627,544		627,544	2
8,977				740,117		740,117	3
4,790				239,621		239,621	4
8,367				558,111		558,111	5
8,868				731,697		731,697	6
7,382				604,335		604,335	7
1,145				71,696		71,696	8
8,544				702,228		702,228	9
282				17,665		17,665	10
8,281				554,207		554,207	11
57				4,273		4,273	12
9,194				611,733		611,733	13
8,853				588,359		588,359	14
10,834,182			109,348,280	597,919,758		707,268,038	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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 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.
31				1,955		1,955	1
13				433		433	2
19				1,204		1,204	3
552				42,236		42,236	4
3				120		120	5
1,122				75,227		75,227	6
							7
18,436				1,186,972		1,186,972	8
5				181		181	9
1				48		48	10
8,803				517,188		517,188	11
6,766				452,349		452,349	12
8,777				587,566		587,566	13
8,956				593,958		593,958	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
6,202				414,498		414,498	1
							2
60,451				3,445,682		3,445,682	3
8,543				570,911		570,911	4
9				310		310	5
3,710				242,009		242,009	6
8,614				572,193		572,193	7
7				231		231	8
9,086				593,793		593,793	9
9,469				629,821		629,821	10
9,480				630,313		630,313	11
8,806				729,407		729,407	12
500				38,293		38,293	13
3,398				281,309		281,309	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
-1				-40		-40	1
6,769				565,992		565,992	2
3,662				300,733		300,733	3
3,253				269,464		269,464	4
8,340				686,087		686,087	5
340				21,319		21,319	6
1				86		86	7
8,518				701,800		701,800	8
8,647				712,039		712,039	9
8,235				673,852		673,852	10
9,319				618,831		618,831	11
8,990				600,053		600,053	12
93				7,127		7,127	13
				-1		-1	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
7,699				631,232		631,232	1
8,714				583,738		583,738	2
8,826				552,549		552,549	3
8,843				580,345		580,345	4
8,645				577,075		577,075	5
8,341				691,774		691,774	6
9,635				638,052		638,052	7
8,942				593,315		593,315	8
9,326				616,679		616,679	9
9,455				586,948		586,948	10
107,673				5,823,748		5,823,748	11
10,251				682,672		682,672	12
103,718				5,713,020		5,713,020	13
							14
10,834,182			109,348,280	597,919,758		707,268,038	

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.
8,886				560,060		560,060	1
7,991				502,211		502,211	2
139,516				7,568,597		7,568,597	3
9,761				604,612		604,612	4
11				391		391	5
15				516		516	6
8,874				560,206		560,206	7
9,972				624,415		624,415	8
57				2,774		2,774	9
605				41,262		41,262	10
443				30,324		30,324	11
561				30,577		30,577	12
9,281				479,430		479,430	13
				171,915		171,915	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
8,524				569,146		569,146	1
4,966				311,219		311,219	2
5,920				379,333		379,333	3
7,731				488,470		488,470	4
482				28,464		28,464	5
6,996				371,899		371,899	6
							7
3,122				200,454		200,454	8
6,504				421,829		421,829	9
14				622		622	10
5,690				385,481		385,481	11
							12
3,395				233,046		233,046	13
4,620				301,132		301,132	14
10,834,182			109,348,280	597,919,758		707,268,038	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,769				240,093		240,093	1
2,495				158,580		158,580	2
2,396				145,347		145,347	3
2,347				129,261		129,261	4
2,138				131,998		131,998	5
1,845				105,531		105,531	6
2,700				162,882		162,882	7
2,158				126,752		126,752	8
135				11,500		11,500	9
3,540				218,476		218,476	10
							11
519				26,305		26,305	12
8				286		286	13
2,040,524			45,981,142	97,693,793		143,674,935	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
				5,358		5,358	1
71,618			12,619,900	10,675,949		23,295,849	2
				-8,923		-8,923	3
1,141,606			13,448,453	39,414,085		52,862,538	4
				-6,246		-6,246	5
100,397				5,020,465		5,020,465	6
				-117,365		-117,365	7
			348,600			348,600	8
			5,388			5,388	9
549,410			36,944,797	28,392,905		65,337,702	10
				4,794		4,794	11
1,882,999				84,538,119		84,538,119	12
309				259,864		259,864	13
333				15,390		15,390	14
10,834,182			109,348,280	597,919,758		707,268,038	

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)	
				-284,503		-284,503	1
890				265,572		265,572	2
4,231				187,440		187,440	3
3,510				149,850		149,850	4
4,774				216,948		216,948	5
4,494				207,893		207,893	6
-26				2,273		2,273	7
3,087				98,040		98,040	8
1,166				31,415		31,415	9
57				2,859		2,859	10
1,796				105,431		105,431	11
9,321				494,517		494,517	12
75				3,192		3,192	13
5,850				246,672		246,672	14
10,834,182			109,348,280	597,919,758		707,268,038	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Southeastern Power Administration (Kerr)	various	various	OLF
2	Brookfield Energy Marketing LP	various	various	SFP
3	Duke Energy Company Revenue Sharing	various	various	OS
4	Duke Power Company	various	various	SNF
5	Exelon Power Team	various	various	SFP
6	Exelon Power Team	various	various	NF
7	Florida Power Corp	various	various	SNF
8	Industrial Power Generating Company L.L.C	various	various	LFP
9	Industrial Power Generating Company L.L.C	various	various	AD
10	Macquarie Energy LLC	various	various	SFP
11	Macquarie Energy LLC	various	various	NF
12	Macquarie Energy LLC	various	various	AD
13	North Carolina Electric Membership	various	various	LFP
14	North Carolina Electric Membership	various	various	SNF
15	North Carolina Municipal Power Agency 1	various	various	SNF
16	North Carolina Municipal Power Agency 1	various	various	SFP
17	North Carolina Municipal Power Agency 1	various	various	AD
18	NTE Carolinas LLC	various	various	SNF
19	Southern Wholesale	various	various	SNF
20	NTE Carolinas LLC	various	various	SFP
21	Tenaska Power Services Co	various	various	SNF
22	Tennessee Valley Authority	various	various	SNF
23	Tennessee Valley Authority	various	various	SFP
24	The Energy Authority	various	various	SNF
25	The Energy Authority	various	various	AD
26	MWH Received and Delivered	various	various	OLF
27	Town of Black Creek N.C.	various	various	FNO
28	Town of Black Creek N.C.	various	various	AD
29	City of Camden	various	various	FNO
30	City of Camden	various	various	AD
31	French Broad EMC	various	various	FNO
32	French Broad EMC	various	various	AD
33	Public Works Commisssion of the City of	various	various	FNO
34	Public Works Commisssion of the City of	various	various	AD
	TOTAL			

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	Haywood EMC	various	various	FNO
2	Haywood EMC	various	various	AD
3	Town of Lucama	various	various	FNO
4	Town of Lucama	various	various	AD
5	North Carolina EMC	various	various	FNO
6	North Carolina Eastern Municipal Power	various	various	FNO
7	North Carolina Eastern Municipal Power	various	various	AD
8	Piedmont EMC	various	various	FNO
9	Piedmont EMC	various	various	AD
10	Town of Sharpsburg	various	various	FNO
11	Town of Sharpsburg	various	various	AD
12	Town of Stantonsburg	various	various	FNO
13	Town of Stantonsburg	various	various	AD
14	Town of Waynesville	various	various	FNO
15	Town of Waynesville	various	various	AD
16	Town of Winterville	various	various	FNO
17	Town of Winterville	various	various	AD
18	Craven County	various	various	OS
19	Elizabethtown Energy LLC	various	various	OS
20	Lumberton Energy LLC	various	various	OS
21	Uwharrie Mountain Renewable Energy	various	various	OS
22	ROE			
23	OATT Settlement Accrual			
24	DEP OATT TAX ACCRUAL			
25	DEP OATT M&S INVENTORY ACCRUAL			
26	DEP OATT (FILED 6-1-17) PARTIAL			
27	DEP OATT M&S INVENTORY REVERSAL			
28	Miscellaneous			
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.
RS127	PJM	CPLE	844			1
	YAD	PJM				2
						3
						4
						5
						6
						7
	CPLE	CPLE	48			8
						9
	various	various				10
						11
						12
	CPLE	DUKE	3,780			13
						14
	CPLE	PJM				15
						16
						17
						18
	CPLE	CPLE				19
						20
						21
						22
						23
	CPLE	CPLE				24
						25
				2,130,923	2,083,585	26
	CPLE	CPLE				27
						28
JointOATT/309	CPLE	CPLE				29
						30
	CPLE	CPLE				31
						32
						33
						34
			4,672	**2,130,923**	**2,083,585**	

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.
	CPLW	CPLW				1
						2
	CPLE	CPLE				3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
JointOATT/271						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			4,672	**2,130,923**	**2,083,585**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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.
1,157,629			1,157,629	1
9,992		863	10,855	2
2,557,051			2,557,051	3
				4
65,013		5,562	70,575	5
55,595		4,813	60,408	6
-6,772		-571	-7,343	7
70,260		5,870	76,130	8
-3,251			-3,251	9
1,089,003		92,473	1,181,476	10
569,773		48,284	618,057	11
-11,317			-11,317	12
2,923,938		242,132	3,166,070	13
218,321		18,546	236,867	14
1,238,536		104,383	1,342,919	15
393,816		33,454	427,270	16
-21,595			-21,595	17
440,362		37,937	478,299	18
4,616		398	5,014	19
88,120		7,540	95,660	20
1,523		134	1,657	21
9,157		779	9,936	22
63,954		5,645	69,599	23
414,791		35,457	450,248	24
-1,368			-1,368	25
				26
49,480		14,615	64,095	27
-1,822			-1,822	28
698,553		63,807	762,360	29
-25,502			-25,502	30
1,502,345		197,608	1,699,953	31
-53,082			-53,082	32
6,549,691		591,954	7,141,645	33
-242,933			-242,933	34
66,718,941	**0**	**5,995,343**	**72,714,285**	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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.
594,424		71,370	665,794	1
-21,042			-21,042	2
74,653		19,608	94,261	3
-2,805			-2,805	4
33,277,560		2,466,799	35,744,361	5
19,179,025		1,701,223	20,880,247	6
-728,781			-728,781	7
429,442		66,421	495,863	8
-15,751			-15,751	9
64,444		17,578	82,022	10
-2,522			-2,522	11
76,323		20,257	96,580	12
-2,843			-2,843	13
240,987		47,794	288,781	14
-9,061			-9,061	15
211,985		50,458	262,443	16
-7,741			-7,741	17
		10,500	10,500	18
		1,800	1,800	19
		4,800	4,800	20
		5,052	5,052	21
-1,758,484			-1,758,484	22
-641,060			-641,060	23
-3,220,695			-3,220,695	24
-3,023,373			-3,023,373	25
928,329			928,329	26
1,276,000			1,276,000	27
-3,950			-3,950	28
				29
				30
				31
				32
				33
				34
66,718,941	**0**	**5,995,343**	**72,714,285**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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 Progress	LFP	2,173,465	2,219,916				
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,173,465	2,219,916				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	727,449
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,427,666
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 Copmany Support	-26,331,563
7	Allocated Incentives	1,514
8	Suspense Clearing	-2,545,979
9	Environmental Accrual Adjustment	2,565,886
10	Consultants and Contract Services	785,481
11	Labor Accrual	1,320,862
12	Restricted Stock Units	497,483
13	Other Contracts	9,467
14	Allocated Labor	13,121
15	Travel	179,709
16	Directed Purchase Allocations	216,634
17	Personal Vehicle Mileage Reimbursement	1,957
18	Postage and Freight	6,813
19	Rent	5,276
20	Sponsorships	
21	Miscellaneous < $5k	14,690
22	Miscellaneous > $5k	
23	Moving Expenses	990,897
24	Dues and Subscriptions to Various Organizations	265,024
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	-19,847,613

Schedule Page: 335 Line No.: 3 Column: b

In prior years, the Research & Development - Alternative Energy account 0930800 activity was being captured in Line 2 - Nuclear Power Research Expenses. For 2018, we are including this account in Line 3 - Other Experimental and General Research Expenses due to the research activity in this account being general in nature and not specifically related to nuclear research. Therefore, leaving Line 2 at a zero balance for 2018. Line 3 is now made up of account 0930700 (Research and Development) & 0930800 (Research & Development - Alternative Energy). All activity related to Other Experimental and General Research Expenses totaling $1,427,666 for 2018 presented on Line 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	04/12/2019	End of 2018/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			42,089,773		42,089,773
2	Steam Production Plant	132,358,759				132,358,759
3	Nuclear Production Plant	232,446,079				232,446,079
4	Hydraulic Production Plant-Conventional	4,558,379				4,558,379
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	119,289,977				119,289,977
7	Transmission Plant	47,475,970				47,475,970
8	Distribution Plant	180,984,372				180,984,372
9	Regional Transmission and Market Operation					
10	General Plant	29,309,745		526		29,310,271
11	Common Plant-Electric					
12	TOTAL	746,423,281		42,090,299		788,513,580

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	Steam Production Plant						
13	310 Land Rights						
14	310 Mayo Unit 1	14,680	100.00		0.78	R4	18.40
15	311.00 Structures and I						
16	311 Asheville Unit 1	41,443	100.00	-0.04	0.95	R2.5	11.00
17	311 Asheville Unit 2	42,579	100.00	-0.04	3.13	R2.5	11.00
18	311 Mayo Unit 1	165,983	100.00	-0.06	1.95	R2.5	18.30
19	311 Roxboro Common	171,353	100.00	-0.06	5.03	R2.5	11.40
20	311 Roxboro Unit 1	17,118	100.00	-0.06	2.52	R2.5	11.40
21	311 Roxboro Unit 2	5,517	100.00	-0.06	3.42	R2.5	16.40
22	311 Roxboro Unit 3	37,372	100.00	-0.06	0.87	R2.5	16.30
23	311 Roxboro Unit 4	19,547	100.00	-0.06	3.60	R2.5	16.40
24	312.00 Boiler Plant Equ						
25	312 Asheville Unit 1	149,751	60.00	-0.04	4.19	R1	10.70
26	312 Asheville Unit 2	145,625	60.00	-0.04	2.94	R1	10.70
27	312 Mayo Unit 1	820,718	60.00	-0.06	4.02	R1	17.40
28	312 Roxboro Common	236,443	60.00	-0.06	1.91	R1	15.80
29	312 Roxboro Unit 1	212,219	60.00	-0.06	6.56	R1	11.10
30	312 Roxboro Unit 2	309,542	60.00	-0.06	5.04	R1	11.10
31	312 Roxboro Unit 3	332,342	60.00	-0.06	4.74	R1	15.60
32	312 Roxboro Unit 4	399,247	60.00	-0.06	1.33	R1	15.70
33	312.10 Boiler Plant Equ						
34	312.1 Asheville Unit 1	3,863	10.00		4.47	S2	6.00
35	312.1 Asheville Unit 2	1,798	10.00		5.44	S2	4.70
36	312.1 Mayo Unit 1	7,429	10.00		5.49	S2	4.60
37	312.1 Roxboro Unit 1	7,925	10.00		1.84	S2	4.80
38	312.1 Roxboro Unit 2	5,857	10.00		3.91	S2	5.80
39	312.1 Roxboro Unit 3	6,542	10.00		7.92	S2	4.80
40	312.1 Roxboro Unit 4	7,262	10.00		1.22	S2	4.20
41	314.00 Turbogenerator U						
42	314 Asheville Unit 1	18,830	60.00	-0.04	6.65	S0	10.60
43	314 Asheville Unit 2	13,969	60.00	-0.04	1.12	S0	10.80
44	314 Mayo Unit 1	106,833	60.00	-0.06	3.04	S0	16.80
45	314 Roxboro Common	459	60.00	-0.06	2.36	S0	15.30
46	314 Roxboro Unit 1	45,629	60.00	-0.06	6.66	S0	11.10
47	314 Roxboro Unit 2	44,957	60.00	-0.06	7.10	S0	11.10
48	314 Roxboro Unit 3	73,034	60.00	-0.06	4.39	S0	15.70
49	314 Roxboro Unit 4	69,535	60.00	-0.06	3.26	S0	15.30
50	315.00 Accessory Electr						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	315 Asheville Unit 1	17,315	65.00	-0.04	4.75	R1.5	10.80
13	315 Asheville Unit 2	10,774	65.00	-0.04		R1.5	
14	315 Mayo Unit 1	65,824	65.00	-0.06	3.55	R1.5	17.60
15	315 Roxboro Common	22,775	65.00	-0.06	5.01	R1.5	15.90
16	315 Roxboro Unit 1	27,912	65.00	-0.06	7.40	R1.5	11.20
17	315 Roxboro Unit 2	24,224	65.00	-0.06	3.55	R1.5	11.20
18	315 Roxboro Unit 3	42,508	65.00	-0.06	4.61	R1.5	15.80
19	315 Roxboro Unit 4	43,315	65.00	-0.06	3.05	R1.5	15.70
20	316.00 Miscellaneous Po						
21	316 Asheville Unit 1	11,618	50.00	-0.04	6.45	S0	10.60
22	316 Asheville Unit 2		50.00	-0.04	1.74	S0	10.60
23	316 Mayo Unit 1	13,238	50.00	-0.06	3.89	S0	16.80
24	316 Roxboro Common	20,617	50.00	-0.06	5.46	S0	15.50
25	316 Roxboro Unit 1	4,073	50.00	-0.06	6.19	S0	11.00
26	316 Roxboro Unit 2	4,358	50.00	-0.06	3.85	S0	11.00
27	316 Roxboro Unit 3	4,582	50.00	-0.06	4.18	S0	15.30
28	316 Roxboro Unit 4	5,429	50.00	-0.06	3.83	S0	15.00
29	Nuclear Production Plan						
30	320 Land Rights						
31	320 Harris Unit 1	56,390	100.00		1.31	R4	29.50
32	320.10 Rights of Way						
33	320.1 Brunswick Unit 1	268	100.00		0.89	R4	19.60
34	320.1 Brunswick Unit 2	3,793	100.00		0.17	R4	17.80
35	321.00 Structures and I						
36	321 Brunswick Unit 1	365,319	80.00	-0.02	2.62	S1	19.10
37	321 Brunswick Unit 2	398,789	80.00	-0.02	2.64	S1	17.50
38	321 Harris Allowance	-310,447			1.29	0	29.80
39	321 Harris Unit 1	1,801,398	80.00	-0.03	1.64	S1	27.30
40	321 Robinson Unit 2	374,019	80.00	-0.01	3.40	S1	13.40
41	322.00 Reactor Plant Eq						
42	322 Brunswick Unit 1	609,972	55.00	-0.02	2.80	R1.5	18.20
43	322 Brunswick Unit 2	545,111	55.00	-0.02	2.87	R1.5	16.80
44	322 Harris Disallowance	-77,489			1.29	0	29.80
45	322 Harris Unit 1	994,052	55.00	-0.03	2.73	R1.5	25.00
46	322 Robinson Unit 2	461,908	55.00	-0.01	3.40	R1.5	12.80
47	323.00 Turbogeneratior						
48	323 Brunswick Unit 1	284,630	50.00	-0.02	3.06	S0	17.70
49	323 Brunswick Unit 2	172,453	50.00	-0.02	3.32	S0	16.40
50	323 Harris Disallowance	-68,842			1.29	0	29.80

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	323 Harris Unit 1	512,228	50.00	-0.03	2.48	S0	25.00
13	323 Robinson Unit 2	333,990	50.00	-0.01	5.04	S0	12.80
14	324.00 Accessory Electr						
15	324 Brunswick Unit 1	161,152	55.00	-0.02	3.77	R2.5	18.90
16	324 Brunswick Unit 2	210,384	55.00	-0.02	3.20	R2.5	17.40
17	324 Harris Disallowance	-52,557			1.29	0	29.80
18	324 Harris Unit 1	757,544	55.00	-0.03	1.86	R2.5	25.60
19	324 Robinson Unit 2	278,377	55.00	-0.01	3.84	R2.5	13.20
20	325.00 Miscellaneous Pl						
21	325 Brunswick Unit 1	158,758	50.00	-0.02	3.56	R1	18.10
22	325 Brunswick Unit 2	68,906	50.00	-0.02	3.52	R1	16.60
23	325 Harris Disallowance	-41,963			1.29	0	29.80
24	325 Harris Unit 1	238,102	50.00	-0.03	2.36	R1	25.00
25	325 Robinson Unit 2	190,310	50.00	-0.01	5.61	R1	12.90
26	Hydraulic Production Pl						
27	330.10 Rights of Way						
28	330.1 Blewett	500	110.00		2.22	R4	18.00
29	330.1 Marshall	464	110.00		2.82	R4	13.30
30	330.1 Tillery	1,152	110.00		1.41	R4	26.40
31	330.1 Walters	713	110.00		2.71	R4	16.10
32	331.00 Structures and I						
33	331 Blewett	6,598	110.00	-0.41	2.59	R2	36.40
34	331 Marshall	1,503	110.00	-0.16	6.77	R2	18.10
35	331 Tillery	6,650	110.00	-0.33	2.37	R2	35.60
36	331 Walters	3,474	110.00	-0.06	3.15	R2	17.10
37	332.00 Reservoirs, Dams						
38	332 Blewett	8,466	120.00	-0.41	2.22	R3	36.10
39	332 Marshall	4,075	120.00	-0.16	3.30	R3	18.30
40	332 Tillery	6,797	120.00	-0.33	1.82	R3	36.40
41	332 Walters	34,636	120.00	-0.06	2.87	R3	17.30
42	333.00 Water Wheels, Tu						
43	333 Blewett	13,437	70.00	-0.41	4.84	R1.5	30.40
44	333 Marshall	4,463	70.00	-0.06	3.14	R1.5	17.30
45	333 Tillery	5,946	70.00	-0.16	2.98	R1.5	33.00
46	333 Walters	14,150	70.00	-0.33	3.86	R1.5	16.50
47	334.00 Accessory Electr						
48	334 Blewett	8,704	60.00	-0.41	3.81	S1	35.00
49	334 Marshall	1,180	60.00	-0.16	3.44	S1	16.50
50	334 Tillery	3,855	60.00	-0.33	3.40	S1	30.90

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	334 Walters	13,947	60.00	-0.06	5.62	S1	17.20
13	335.00 Miscellaneous Pl						
14	335 Blewett	1,430	55.00	-0.41	3.77	S0.5	30.20
15	335 Marshall	201	55.00	-0.16	5.23	S0.5	17.10
16	335 Tillery	1,137	55.00	-0.33	2.70	S0.5	31.10
17	335 Walters	1,743	55.00	-0.06	4.83	S0.5	16.50
18	336.00 Roads, Railroads						
19	336 Marshall	13	75.00	-0.16	2.84	R3	17.70
20	336 Walters	8	75.00	-0.06	0.52	R3	12.70
21	Other Production Plant						
22	340.10 Right of Way						
23	340.1 Wayne Count Units	4,581	60.00		2.76	R4	23.00
24	341.00 Structures and I						
25	341 Asheville IC Turbin	31,763	50.00	-0.03	2.95	S2	20.40
26	341 Blewett IC Turbine	980	50.00	-0.07	1.36	S2	7.50
27	341 Darlington IC Turbi	8,428	50.00	-0.06	0.15	S2	20.30
28	341 Smith CC Block 4	47,694	50.00	-0.03	0.90	S2	23.20
29	341 Smith CC Block 5	40,103	50.00	-0.07	2.89	S2	32.00
30	341 Smith IC Turbine	19,345	50.00	-0.02	2.89	S2	23.00
31	341 Sutton CC	24,785	50.00	-0.02	3.54	S2	34.00
32	341 Wayne County CC	25,476	50.00	-0.05	2.38	S2	30.60
33	341 Wayne County IC Tur	8,984	50.00	-0.04	2.66	S2	21.50
34	341 Wayne County IC Tur	1,357	50.00	-0.04	2.74	S2	30.10
35	341 Weatherspoon IC Tur	3,569	50.00	-0.20	1.51	S2	7.10
36	342.00 Feul Holders, Pr						
37	342 Asheville IC Turbin	5,116	50.00	-0.03	2.25	R2.5	21.00
38	342 Blewett IC Turbine	413	50.00	-0.07	1.86	R2.5	7.40
39	342 Darlington IC Turbi	5,048	50.00	-0.06		R2.5	
40	342 Darlington IC Turbi	7,239	50.00	-0.06	1.32	R2.5	19.70
41	342 Smith CC Block 4	13,524	50.00	-0.03	2.74	R2.5	23.50
42	342 Smith CC Block 5	22,575	50.00	-0.07	2.92	R2.5	31.70
43	342 Smith IC Turbine	8,474	50.00	-0.02	3.01	R2.5	22.50
44	342 Sutton CC	25,647	50.00	-0.02	2.93	R2.5	33.60
45	342 Wayne County CC	25,423	50.00	-0.05	3.07	R2.5	32.70
46	342 Wayne County IC Tur	7,410	50.00	-0.04	2.77	R2.5	21.70
47	342 Wayne County IC Tur	1,461	50.00	-0.04	2.99	R2.5	27.50
48	342 Weatherspoon IC Tur	1,651	50.00	-0.20	5.30	R2.5	7.50
49	343.00 Prime Movers						
50	343 Asheville IC Turbin	51,865	35.00	-0.03	3.18	S0	18.50

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	343 Blewett IC Turbine	8,456	35.00	-0.07	3.76	S0	6.70
13	343 Darlington IC Turbi	22,499	35.00	-0.06	19.72	S0	3.40
14	343 Darlington IC Turbi	38,585	35.00	-0.06	5.32	S0	17.10
15	343 Smith CC Block 4	114,272	35.00	-0.03	5.72	S0	19.90
16	343 Smith CC Block 5	296,175	35.00	-0.07	3.84	S0	25.50
17	343 Smith IC Turbine	184,975	35.00	-0.02	5.46	S0	19.80
18	343 Sutton CC	65,020	35.00	-0.02	3.56	S0	27.10
19	343 Wayne County CC	443,714	35.00	-0.05	3.96	S0	26.40
20	343 Wayne County IC Tur	121,712	35.00	-0.04	3.82	S0	19.00
21	343 Wayne County IC Tur	61,526	35.00	-0.04	3.46	S0	24.20
22	343 Weatherspoon IC Tur	12,638	35.00	-0.20	0.19	S0	6.90
23	343.10 Prime Movers - R						
24	343.1 Smith CC Block 4	39,318	5.00	0.40	13.49	L0.5	4.60
25	343.1 Smith CC Block 5	33,786	5.00	0.40	15.17	L0.5	3.20
26	343.1 Sutton CC	391,025	5.00	0.40	14.68	L0.5	3.50
27	343.1 Wayne County CC	56,542	5.00	0.40	14.68	L0.5	4.10
28	344.00 Generators						
29	344 Asheville IC Turbin	7,770	55.00	-0.03	2.83	R2	20.90
30	344 Blewett IC Turbine	1,988	55.00	-0.07		R2	
31	344 Darlington IC Turbi	12,473	55.00	-0.06	11.27	R2	3.50
32	344 Darlington IC Turbi	17,132	55.00	-0.06	3.92	R2	19.30
33	344 Smith CC Block 4	40,449	55.00	-0.03	1.07	R2	24.00
34	344 Smith CC Block 5	31,517	55.00	-0.07	2.90	R2	31.70
35	344 Smith IC Turbine	37,042	55.00	-0.02	5.43	R2	22.60
36	344 Sutton CC	46,628	55.00	-0.02	2.88	R2	33.50
37	344 Wayne County CC	55,122	55.00	-0.05	3.07	R2	32.60
38	344 Wayne County IC Tur	22,069	55.00	-0.04	2.90	R2	21.70
39	344 Wayne County IC Tur	13,021	55.00	-0.04	2.85	R2	29.80
40	344 Weatherspoon IC Tur	2,096	55.00	-0.20		R2	
41	344.00 Generators - Sol						
42	344 Camp Lejenue	15,104	25.00	-0.08	5.03	S2.5	20.70
43	344 Fayetteville	31,027	25.00	-0.10	5.12	S2.5	20.70
44	344 Elm City	49,456	25.00	-0.15	5.17	S2.5	21.70
45	344 Warsaw	83,159	25.00	-0.11	5.18	S2.5	20.70
46	345.00 Accessory Electr						
47	345 Asheville IC Turbin	13,502	50.00	-0.03	3.67	R1.5	20.50
48	345 Blewett IC Turbine	1,419	50.00	-0.07	1.18	R1.5	7.40
49	345 Darlington IC Turbi	4,869	50.00	-0.06	7.99	R1.5	3.50
50	345 Darlington IC Turbi	10,725	50.00	-0.06	3.73	R1.5	18.80

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	345 Smith CC Block 4	21,653	50.00	-0.03	3.18	R1.5	23.00
13	345 Smith CC Block 5	51,328	50.00	-0.07	3.06	R1.5	30.40
14	345 Smith IC Turbine	29,203	50.00	-0.02	3.02	R1.5	22.10
15	345 Sutton CC	76,513	50.00	-0.02	3.15	R1.5	32.20
16	345 Wayne County CC	76,515	50.00	-0.05	3.25	R1.5	31.30
17	345 Wayne County IC Tur	19,927	50.00	-0.04	3.01	R1.5	21.10
18	345 Wayne County IC Tur	10,599	50.00	-0.04	2.94	R1.5	28.70
19	345 Weatherspoon IC Tur	2,926	50.00	-0.20	8.62	R1.5	7.20
20	345.00 Accessory Electr						
21	345 Camp Lejenue	2,761	25.00	-0.08	5.01	S2.5	20.80
22	345 Fayetteville	533	25.00	-0.10	5.13	S2.5	20.70
23	345 Elm City	133	25.00	-0.15	5.17	S2.5	21.60
24	345 Warsaw	1,259	25.00	-0.11	5.17	S2.5	20.70
25	346.00 Miscellaneous Pl						
26	346 Asheville IC Turbin	3,546	40.00	-0.03	3.46	S1.5	18.80
27	346 Blewett IC Turbine	205	40.00	-0.07	10.82	S1.5	7.30
28	346 Darlington IC Turbi	90	40.00	-0.06	0.40	S1.5	3.50
29	346 Darlington IC Turbi	1,391	40.00	-0.06	2.84	S1.5	19.10
30	346 Smith CC Block 4	4,901	40.00	-0.03	2.36	S1.5	23.50
31	346 Smith CC Block 5	8,420	40.00	-0.07	3.16	S1.5	28.80
32	346 Smith IC Turbine	7,601	40.00	-0.02	5.41	S1.5	20.80
33	346 Sutton CC	10,188	40.00	-0.02	3.19	S1.5	31.00
34	346 Wayne County CC	11,746	40.00	-0.05	3.28	S1.5	29.60
35	346 Wayne County IC Tur	1,317	40.00	-0.04	2.18	S1.5	20.20
36	346 Wayne County IC Tur	1,126	40.00	-0.04	2.61	S1.5	26.90
37	346 Weatherspoon IC Tur	721	40.00	-0.20	13.60	S1.5	7.40
38	Transmission Plant						
39	350.1 Rights of Way	184,823	75.00		1.15	0	53.80
40	352 Structures and Impr	89,514	60.00	-0.10	1.78	R3	43.30
41	353 Station Equipment	1,060,543	60.00	-0.15	1.90	R1	48.80
42	354 Towers and Fixtures	77,233	70.00	-0.20	1.35	R4	41.40
43	355 Poles and Fixtures	738,981	48.00	-0.30	2.22	R1.5	41.20
44	356 OH conductors and D	568,576	70.00	-0.30	1.56	R2	58.10
45	358 UG Conductor and De	24	45.00		2.30	S2.5	41.50
46	359 Roads and Trails	313	75.00		1.37	R3	59.20
47	Distribution Plant						
48	360.1 Right of Way	31,939	65.00		1.28	R3	40.60
49	361 Structures and Impr	125,310	60.00	-0.15	1.52	R2	47.30
50	362 Station Equipment	670,872	46.00	-0.15	2.33	R1	35.70

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	364 Poles, Towers, and	822,217	45.00	-1.00	3.95	R2.5	31.30
13	365 OH Conductors and D	1,182,130	44.00	-0.30	2.15	R1.5	35.70
14	366 Underground Conduit	198,958	45.00	-0.10	2.26	S2.5	33.40
15	367 Underground Conduct	1,129,766	40.00	-0.05	1.76	S2	28.60
16	368 Line Transformers	1,095,082	39.00	-0.05	2.54	R2	27.50
17	369 Services	508,642	42.00	-0.10	1.96	R3	29.30
18	370 Meter Equipment	198,089	30.00	-0.15	3.41	R4	20.80
19	370 Meters	1,139	30.00	-0.05	3.91	R4	10.00
20	370 Meters-UOF	66,889	17.00		6.41	S2.5	12.50
21	371 Installations on Cu	319,259	25.00	-0.10	1.15	L1.5	20.40
22	373 Street Lighting and	260,382	30.00	-0.10	3.87	R1	26.90
23	389.1 Rights of Way	52	60.00		51.51	R3	28.20
24	General Plant						
25	390 Structures and Impr	155,191	45.00	-0.05	2.42	R1.5	34.40
26	391 Office Furniture an	23,433	20.00		5.00	SQ	6.90
27	391.1 Office funture an	59,930	8.00		12.50	SQ	4.80
28	392 Transportation Equi	69,791	11.00	0.10	10.29	L2	5.80
29	393 Stores Equipment	2,060	20.00		5.00	SQ	10.00
30	394 Tool, shop, garage	86,573	20.00		5.00	SQ	13.20
31	395 Laboratory Equipmen	6,740	15.00		6.67	SQ	7.60
32	396 Power Operated Equi	5,680	12.00		5.99	S6	8.30
33	397 Communication Equip	174,657	20.00		5.00	SQ	11.10
34	398 Misc Equipment	25,018	20.00		5.00	SQ	6.80
35							
36							
37							
38							
39							
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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)	1,011,639		1,011,639	248,168
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	1,905,198		1,905,198	
13					
14	Annual Charges Assessed by the NC Utilities				
15	Commission as required by Senate Bill 1320	4,591,694		4,591,694	
16					
17	Annual Charges Assessed by the SC Public				
18	Service Commission	755,645		755,645	
19					
20					
21	SC Rate Case Amortization (5 years)	30,587		30,587	122,348
22					
23					
24	Other	3,900		3,900	
25					
26					
27	NC Regulatory Fee Amortization	297,533		297,533	
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	8,596,196		8,596,196	370,516

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	1,011,639	3,730,201	7
							8
							9
							10
							11
Electric	928	1,905,198					12
							13
							14
Electric	928	4,591,694					15
							16
							17
Electric	928	755,645					18
							19
							20
Electric	928	30,587					21
							22
							23
Electric	928	3,900					24
							25
							26
				182.3	297,533	1,497,978	27
							28
							29
							30
							31
							32
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							36
							37
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							41
							42
							43
							44
							45
		7,287,024			1,309,172	5,228,179	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Electric R, D&D Performed Internally:	
2		
3	(3) Distribution	Research & Development Administration Costs
4		
5	(7) TOTAL ELECTRIC R, D&D PERFORMED INTERNALLY	
6		
7	B. Electric R, D&D Performed Externally:	
8		
9	(1) Electric Power Research Institute	Electric Power Research Institute Membership
10		EPRI Nuclear Co-Funding
11		Others (Less Than $50K each)
12		
13	(4) Research Support to Others	Alternative Energy (Advanced Energy Research)
14		
15	(5) TOTAL ELECTRIC R, D&D PERFORMED EXTERNALLY	
16		
17		
18		
19		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
47,691		930.7	47,691		3
					4
47,691			47,691		5
					6
					7
					8
	6,420,775	Various	6,420,775		9
	780,050	Various	780,050		10
	30,166	Various	30,166		11
					12
	1,379,975	930.8	1,379,975		13
					14
	8,610,966		8,610,966		15
					16
					17
					18
					19
					20
					21
					22
					23
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	221,082,961		
4	Transmission	8,332,490		
5	Regional Market			
6	Distribution	20,838,503		
7	Customer Accounts	21,023,608		
8	Customer Service and Informational	2,244,420		
9	Sales	4,977,267		
10	Administrative and General	144,784,387		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	423,283,636		
12	Maintenance			
13	Production	166,244,358		
14	Transmission	10,965,389		
15	Regional Market			
16	Distribution	49,241,516		
17	Administrative and General	139,214		
18	TOTAL Maintenance (Total of lines 13 thru 17)	226,590,477		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	387,327,319		
21	Transmission (Enter Total of lines 4 and 14)	19,297,879		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	70,080,019		
24	Customer Accounts (Transcribe from line 7)	21,023,608		
25	Customer Service and Informational (Transcribe from line 8)	2,244,420		
26	Sales (Transcribe from line 9)	4,977,267		
27	Administrative and General (Enter Total of lines 10 and 17)	144,923,601		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	649,874,113	3,710,561	653,584,674
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	649,874,113	3,710,561	653,584,674
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	163,441,091	14,784,255	178,225,346
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	163,441,091	14,784,255	178,225,346
72	Plant Removal (By Utility Departments)			
73	Electric Plant	30,303,443		30,303,443
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	30,303,443		30,303,443
77	Other Accounts (Specify, provide details in footnote):			
78	Non-Regulated Products and Services	4,750,987		4,750,987
79	Other Work in Progress	4,471,750		4,471,750
80	Other Accounts	7,284,796		7,284,796
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	16,507,533		16,507,533
96	TOTAL SALARIES AND WAGES	860,126,180	18,494,816	878,620,996

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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.

DEP has no common Utility Plant & Expenses to report for year ending 2018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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)	3,244,363	3,647,285	3,661,660	4,903,100
3	Net Sales (Account 447)	198,307	266,495	245,459	247,022
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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19					
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21					
22					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	3,442,670	3,913,780	3,907,119	5,150,122

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				1,540,857	MWH	1,610,891
2	Reactive Supply and Voltage				1,540,857	MWH	3,375,490
3	Regulation and Frequency Response						23,096
4	Energy Imbalance	354	MWH	1,761	20,070		862,444
5	Operating Reserve - Spinning						34,067
6	Operating Reserve - Supplement						24,346
7	Other						
8	Total (Lines 1 thru 7)	354		1,761	3,101,784		5,930,334

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	15,847	7	8	10,309	5,219	319			
2	February	11,959	3	9	7,932	3,708	319			
3	March	11,756	15	8	7,940	3,497	319			
4	Total for Quarter 1				26,181	12,424	957			
5	April	8,564	11	8	5,818	2,427	319			
6	May	11,425	14	18	7,745	3,361	319			
7	June	13,513	19	17	9,093	4,101	319			
8	Total for Quarter 2				22,656	9,889	957			
9	July	13,135	11	18	8,832	3,984	319			
10	August	13,081	8	17	8,767	3,995	319			
11	September	12,596	4	16	8,502	3,775	319			
12	Total for Quarter 3				26,101	11,754	957			
13	October	11,728	5	17	7,936	3,473	319			
14	November	12,060	29	8	8,104	3,637	319			
15	December	12,069	6	8	8,168	3,582	319			
16	Total for Quarter 4				24,208	10,692	957			
17	Total Year to Date/Year				99,146	44,759	3,828			

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	04/12/2019	End of 2018/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)	44,827,278
3	Steam	8,656,835	23	Requirements Sales for Resale (See instruction 4, page 311.)	18,957,867
4	Nuclear	27,490,999	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,547,604
5	Hydro-Conventional	805,640	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	105,149
7	Other	24,182,604	27	Total Energy Losses	2,533,249
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	71,971,147
9	Net Generation (Enter Total of lines 3 through 8)	61,136,078			
10	Purchases	10,834,182			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	2,130,923			
17	Delivered	2,083,585			
18	Net Transmission for Other (Line 16 minus line 17)	47,338			
19	Transmission By Others Losses	-46,451			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	71,971,147			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	7,203,066	391,129	15,322	7	800
30	February	5,280,998	599,167	11,293	3	900
31	March	5,382,664	252,246	11,182	15	800
32	April	4,640,195	255,785	8,012	11	800
33	May	5,595,548	217,953	10,883	14	1700
34	June	6,370,140	225,152	12,841	19	1700
35	July	7,035,470	699,043	12,467	11	1800
36	August	7,113,586	619,139	12,438	8	1700
37	September	6,177,502	441,128	11,918	4	1600
38	October	5,434,600	601,804	11,081	5	1700
39	November	5,517,589	494,723	11,517	29	800
40	December	6,219,789	750,335	11,489	6	800
41	TOTAL	71,971,147	5,547,604			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Asheville* (b)			Plant Name: *Cape Fear* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Conv & Full Outdoor		
3	Year Originally Constructed	1964			1923		
4	Year Last Unit was Installed	1971			1958		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	418.30			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	379			0		
7	Plant Hours Connected to Load	8415			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			4		
12	Net Generation, Exclusive of Plant Use - KWh	1237903000			0		
13	Cost of Plant: Land and Land Rights	4403581			0		
14	Structures and Improvements	85194101			0		
15	Equipment Costs	377370167			0		
16	Asset Retirement Costs	431334286			0		
17	Total Cost	898302135			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	2147.5069			0		
19	Production Expenses: Oper, Supv, & Engr	983784			43		
20	Fuel	50276486			284		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	7093864			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2232			0		
26	Misc Steam (or Nuclear) Power Expenses	2057943			24313		
27	Rents	360			0		
28	Allowances	4058583			9740		
29	Maintenance Supervision and Engineering	826429			22		
30	Maintenance of Structures	1666537			363225		
31	Maintenance of Boiler (or reactor) Plant	4184634			1		
32	Maintenance of Electric Plant	913719			26		
33	Maintenance of Misc Steam (or Nuclear) Plant	1849695			33882		
34	Total Production Expenses	73914266			431536		
35	Expenses per Net KWh	0.0597			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	12505	620610	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137551	12604	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	100.140	82.270	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	92.942	77.776	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	16.088	3.085	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.040	0.040	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	12696.000	12696.000	0.000	0.000	0.000	0.000

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)	2468			0		
7	Plant Hours Connected to Load	7287			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	2462			0		
10	When Limited by Condenser Water	2439			0		
11	Average Number of Employees	220			0		
12	Net Generation, Exclusive of Plant Use - KWh	5927599000			0		
13	Cost of Plant: Land and Land Rights	8105075			0		
14	Structures and Improvements	273549403			0		
15	Equipment Costs	2042920147			0		
16	Asset Retirement Costs	241172244			0		
17	Total Cost	2565746869			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1002.9501			0		
19	Production Expenses: Oper, Supv, & Engr	4234078			186		
20	Fuel	208440486			112382		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	15765522			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	9388			0		
26	Misc Steam (or Nuclear) Power Expenses	7816440			106250		
27	Rents	0			0		
28	Allowances	11145165			42627		
29	Maintenance Supervision and Engineering	3441572			-6		
30	Maintenance of Structures	3352177			-122404		
31	Maintenance of Boiler (or reactor) Plant	24116813			5708		
32	Maintenance of Electric Plant	2838042			1242		
33	Maintenance of Misc Steam (or Nuclear) Plant	4785804			6569		
34	Total Production Expenses	285945487			152554		
35	Expenses per Net KWh	0.0482			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	71275	2415739	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138209	12619	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	91.470	84.880	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	90.083	82.982	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	15.519	3.288	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.035	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10356.000	10356.000	0.000	0.000	0.000	0.000

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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: *H.B. Robinson* (b)	Plant Name: *Asheville* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1971	1999
4	Year Last Unit was Installed	1971	2000
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	768.60	418.80
6	Net Peak Demand on Plant - MW (60 minutes)	803	337
7	Plant Hours Connected to Load	7009	3033
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	797	370
10	When Limited by Condenser Water	741	320
11	Average Number of Employees	700	0
12	Net Generation, Exclusive of Plant Use - KWh	5276118000	506865000
13	Cost of Plant: Land and Land Rights	1663503	565402
14	Structures and Improvements	373564530	31762836
15	Equipment Costs	1265147021	81674453
16	Asset Retirement Costs	219835396	0
17	Total Cost	1860210450	114002691
18	Cost per KW of Installed Capacity (line 17/5) Including	2420.2582	272.2127
19	Production Expenses: Oper, Supv, & Engr	11500181	352962
20	Fuel	38897935	29255228
21	Coolants and Water (Nuclear Plants Only)	3213619	0
22	Steam Expenses	12269119	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1758450	102426
26	Misc Steam (or Nuclear) Power Expenses	35792482	2283811
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	18574026	259994
30	Maintenance of Structures	3461185	1242147
31	Maintenance of Boiler (or reactor) Plant	18734007	0
32	Maintenance of Electric Plant	11180696	1059096
33	Maintenance of Misc Steam (or Nuclear) Plant	15828738	229532
34	Total Production Expenses	171210438	34785196
35	Expenses per Net KWh	0.0325	0.0686

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Nuclear		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MBTUs		MW Days	Barrels	MCF	
38	Quantity (Units) of Fuel Burned	55164268	0	673458	115528	5044436	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	137517	1026117	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	100.140	3.620	0.000
41	Average Cost of Fuel per Unit Burned	0.000	55.678	0.000	94.872	3.620	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.680	0.000	16.426	3.528	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.007	0.000	0.058	0.058	0.000
44	Average BTU per KWh Net Generation	0.000	10451.000	0.000	11529.000	11529.000	0.000

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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: *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	18			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			6		
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			10		
26	Misc Steam (or Nuclear) Power Expenses	0			549		
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			565		
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

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: *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)	910			2161		
7	Plant Hours Connected to Load	1720			14825		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	963			2167		
10	When Limited by Condenser Water	857			1845		
11	Average Number of Employees	6			71		
12	Net Generation, Exclusive of Plant Use - KWh	458014000			11895681000		
13	Cost of Plant: Land and Land Rights	4581022			2839730		
14	Structures and Improvements	116369832			107142081		
15	Equipment Costs	260122416			941987080		
16	Asset Retirement Costs	0			0		
17	Total Cost	381073270			1051968891		
18	Cost per KW of Installed Capacity (line 17/5) Including	388.9693			468.6248		
19	Production Expenses: Oper, Supv, & Engr	306762			3708275		
20	Fuel	36349799			404318467		
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	376483			783163		
26	Misc Steam (or Nuclear) Power Expenses	1480824			3955674		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	922262			2589746		
30	Maintenance of Structures	307097			779030		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	895856			8874665		
33	Maintenance of Misc Steam (or Nuclear) Plant	1093146			5829354		
34	Total Production Expenses	41732229			430838374		
35	Expenses per Net KWh	0.0911			0.0362		
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	208820	3956602	0	116791	93028297	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137643	1033412	0	140000	1026392	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	100.610	3.836	0.000	97.820	4.225	0.000
41	Average Cost of Fuel per Unit Burned	100.973	3.836	0.000	97.626	4.225	0.000
42	Average Cost of Fuel Burned per Million BTU	17.466	3.712	0.000	16.603	4.116	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.079	0.079	0.000	0.034	0.034	0.000
44	Average BTU per KWh Net Generation	11563.000	11563.000	0.000	8084.000	8084.000	0.000

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *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	715	0	6
0	5036	0	7
0	0	0	8
0	746	0	9
0	727	0	10
0	79	0	11
0	1491333000	0	12
0	14994716	0	13
0	170239859	0	14
0	1029684910	0	15
0	154695756	0	16
0	1369615241	0	17
0	1794.5692	0	18
29	1821164	569	19
710	62375235	0	20
0	0	0	21
0	4186831	0	22
0	0	0	23
0	0	0	24
0	5774	0	25
16366	1960801	-3718	26
0	0	0	27
6635	3196586	-1259	28
22	930053	2	29
393360	5813943	28224	30
1	6796191	9040	31
26	626332	342	32
42	4507416	6979	33
417191	92220326	40179	34
0.0000	0.0618	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Oil	Coal					36
			Barrels	Tons					37
0	0	0	32935	730530	0	0	0	0	38
0	0	0	137823	12528	0	0	0	0	39
0.000	0.000	0.000	90.290	81.040	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	88.289	80.994	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	15.253	3.232	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.042	0.042	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	12402.000	12402.000	0.000	0.000	0.000	0.000	44

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *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			1917			1011	6
		0			8608			7844	7
		0			0			0	8
		0			1928			980	9
		0			1870			932	10
		0			908			749	11
		0			14626967000			7587914000	12
		0			4060633			62514104	13
		0			821063020			1892258591	14
		0			2257228968			2233550314	15
		0			305308377			350994010	16
		0			3387660998			4539317019	17
		0			1691.1247			4773.7060	18
		9916			16977982			11445195	19
		3260			96483203			51691177	20
		0			9991295			7707532	21
		0			19834166			11474176	22
		0			0			0	23
		0			0			0	24
		0			743016			1725170	25
		23882			59461855			57375343	26
		0			0			0	27
		13516			0			0	28
		9			40555868			15986769	29
		164486			7348551			4282970	30
		1			25541556			17703630	31
		11			14197152			10190203	32
		17			19056932			12553641	33
		215098			310191576			202135806	34
		0.0000			0.0212			0.0266	35
				Nuclear			Nuclear		36
			MBTUs		MW Days	MBTUs		MW Days	37
0	0	0	155297380	0	1895905	78640141	0	960056	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	50.260	0.000	0.000	53.517	0.000	41
0.000	0.000	0.000	0.000	0.614	0.000	0.000	0.653	0.000	42
0.000	0.000	0.000	0.000	0.007	0.000	0.000	0.007	0.000	43
0.000	0.000	0.000	0.000	10617.000	0.000	0.000	10364.000	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			1968			3
1971			1968			2017			4
70.00			0.00			851.00			5
55			0			2570			6
38			0			10496			7
0			0			0			8
68			0			719			9
52			0			685			10
5			0			61			11
199000			0			3643455000			12
0			0			1208226			13
979563			0			13462879			14
12481298			0			613251137			15
0			0			0			16
13460861			0			627922242			17
192.2980			0			737.8640			18
10094			234			1200540			19
211924			0			156069474			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
4668			9			375797			25
68868			229			2351065			26
0			0			0			27
0			0			0			28
34544			0			1136933			29
15001			0			2590749			30
0			0			0			31
45606			11			12256359			32
282126			0			2817944			33
672831			483			178798861			34
3.3811			0.0000			0.0491			35
Oil						Oil	Gas		36
Barrels						Barrels	MCF		37
2099	0	0	0	0	0	496	26701856	0	38
140489	0	0	0	0	0	136000	1025065	0	39
104.580	0.000	0.000	0.000	0.000	0.000	0.000	5.840	0.000	40
96.784	0.000	0.000	0.000	0.000	0.000	117.689	5.840	0.000	41
16.406	0.000	0.000	0.000	0.000	0.000	30.742	5.697	0.000	42
1.021	0.000	0.000	0.000	0.000	0.000	0.043	0.043	0.000	43
62225.000	0.000	0.000	0.000	0.000	0.000	7513.000	7513.000	0.000	44

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Darlington* (d)			Plant Name: *H.F. Lee* (e)			Plant Name: *W.H. Weatherspoon* (f)			Line No.
		Gas Turbine			Gas Turbine			Gas Turbine	1
		Conventional			Conventional			Conventional	2
		1974			1968			1970	3
		1997			2012			1971	4
		912.20			1068.00			163.00	5
		585			1011			160	6
		1649			7841			59	7
		0			0			0	8
		846			1059			164	9
		664			888			124	10
		0			71			6	11
		230819000			7210666000			1712000	12
		50044			673304			84323	13
		8765528			25476302			3568977	14
		121050791			669150101			20109988	15
		0			0			0	16
		129866363			695299707			23763288	17
		142.3661			651.0297			145.7870	18
		774276			498133			190952	19
		26141469			246443899			766990	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		121312			1332772			17537	25
		979285			3951936			340441	26
		0			0			0	27
		0			0			0	28
		587936			1291417			78716	29
		360595			1135633			55431	30
		0			0			0	31
		551529			1857981			322505	32
		606146			1160722			196277	33
		30122548			257672493			1968849	34
		0.1305			0.0357			1.1500	35
Oil	Gas		Oil	Gas		Oil			36
Barrels	MCF		Barrels	MCF		Barrels			37
188188	1868991	0	0	50701745	0	8091	0	0	38
138227	1024006	0	0	1032173	0	139971	0	0	39
103.100	3.701	0.000	100.610	4.859	0.000	101.120	0.000	0.000	40
101.777	3.701	0.000	0.000	4.859	0.000	93.169	0.000	0.000	41
17.531	3.614	0.000	0.000	4.707	0.000	15.849	0.000	0.000	42
0.113	0.113	0.000	0.034	0.034	0.000	0.440	0.000	0.000	43
13025.000	13025.000	0.000	7258.000	7258.000	0.000	27782.000	0.000	0.000	44

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

Asheville Steam Total fuel costs include Fuel Handling and Sale of Fly Ash.

Schedule Page: 402 Line No.: 20 Column: c

Cape Fear Steam Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: d

HF Lee Steam Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: e

Mayo Steam Total fuel costs include Fuel Handling and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 1 Column: c

Sutton Steam unit 3 was retired on November 3, 2013; units 1 & 2 were retired December 31, 2013.

Schedule Page: 403.1 Line No.: 1 Column: d

Weatherspoon fossil steam units were retired on October 1, 2011.

Schedule Page: 403.1 Line No.: 2 Column: e

Brunswick Nuclear Plant contains two boiling water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 403.1 Line No.: 2 Column: f

Harris Nuclear Plant contains one pressurized water reactor. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 402.1 Line No.: 20 Column: b

Roxboro Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 20 Column: c

Sutton Steam Total fuel costs reflect Sale of Fly Ash.
Accounts 501007 and 501009 for Coal Ash Beneficial Reuse in the amount of $(831,990) are excluded.

Schedule Page: 403.1 Line No.: 20 Column: d

Weatherspoon Steam Total fuel costs include Fuel Handling and Sale of Fly Ash.
Accounts 501007, 501008, and 501009 for Coal Ash Beneficial Reuse in the amount of $7,883,169 are excluded.

Schedule Page: 402.2 Line No.: 1 Column: b

H.B. Robinson Nuclear Plant contains one pressurized water reactor. The nuclear fuel assemblies in the reactor contain enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 402.2 Line No.: 1 Column: c

All Gas Turbine Plants listed on pages 402-403 are peaking plants with the exception of Richmond which includes two combined cycle units (intermediate) and five gas turbine units (peaking) and Lee which includes one combined cycle unit (intermediate) which became commercial on December 31, 2012 and four gas tubine units (peaking) which retired October 1, 2012. (refer to instruction 10)

Schedule Page: 403.2 Line No.: 1 Column: e

Robinson CT unit 3 was retired April 1, 2013.

Schedule Page: 403.2 Line No.: 20 Column: f

Sutton Gas Turbine now includes Sutton CT4 and CT5 with in service date of July 8, 2017.

Schedule Page: 402.3 Line No.: 1 Column: b

Morehead CT was retired on October 1, 2012.

Schedule Page: 402.3 Line No.: 1 Column: c

Cape Fear CT unit 2B was retired on October 1, 2012. Cape Fear CT units 1A, 1B, and 2A were retired on April 1, 2013.

Schedule Page: 403.3 Line No.: 1 Column: d

Darlington CT unit 11 was retired on November 8, 2015.

Schedule Page: 403.3 Line No.: 1 Column: e

Lee CT Units 1,2,3, and 4 were retired on October 1, 2012. Lee Combined Cycle (CC) units CT1A, CT1B, CT1C, and ST1 were placed into service on December 31, 2012.

Schedule Page: 402.4 Line No.: 20 Column: c

Smith Energy Complex Total fuel costs include Biogas accounts 0547106, 0547107 and 0547108 in the amount of $246,444.

Schedule Page: 402 Line No.: 41 Column: b2

Asheville Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling 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 and Sale of Fly Ash.

Schedule Page: 402 Line No.: 43 Column: b1

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: b2

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: e1

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: e2

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: b1

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: b2

Asheville Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: e1

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: e2

Mayo Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 41 Column: b2

Roxboro Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 43 Column: b1

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 43 Column: b2

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 44 Column: b1

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 44 Column: b2

Roxboro Steam Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: c1

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: c2

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: f1

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: f2

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: c1

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: c2

Asheville Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: f1

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: f2

Sutton Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: d1

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: d2

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: e1

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: e2

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: d1

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: d2

Darlington Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: e1

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: e2

Lee Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: b1

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: b2

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: c1

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: c2

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: b1

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: b2

Wayne County Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: c1

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: c2

Smith Energy Complex Gas Turbine Calculated on all fuels basis only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Blewett Hydro (b)	FERC Licensed Project No. 0 Plant Name: Tillery Hydro (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1912	1928
4	Year Last Unit was Installed	1912	1960
5	Total installed cap (Gen name plate Rating in MW)	24.60	84.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	40	85
7	Plant Hours Connect to Load	6,209	5,072
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	5	7
12	Net Generation, Exclusive of Plant Use - Kwh	88,367,000	238,608,000
13	Cost of Plant		
14	Land and Land Rights	500,333	1,151,690
15	Structures and Improvements	6,620,301	6,634,057
16	Reservoirs, Dams, and Waterways	8,275,323	6,796,645
17	Equipment Costs	22,806,578	19,223,068
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	706,699	440,012
20	TOTAL cost (Total of 14 thru 19)	38,909,234	34,245,472
21	Cost per KW of Installed Capacity (line 20 / 5)	1,581.6762	407.6842
22	Production Expenses		
23	Operation Supervision and Engineering	526,429	803,816
24	Water for Power	18,188	44,312
25	Hydraulic Expenses	4,177	-367,596
26	Electric Expenses	17,699	59,743
27	Misc Hydraulic Power Generation Expenses	192,120	205,339
28	Rents	0	0
29	Maintenance Supervision and Engineering	24,105	81,517
30	Maintenance of Structures	15,768	40,227
31	Maintenance of Reservoirs, Dams, and Waterways	54,526	523,157
32	Maintenance of Electric Plant	96,889	200,550
33	Maintenance of Misc Hydraulic Plant	491,935	650,479
34	Total Production Expenses (total 23 thru 33)	1,441,836	2,241,544
35	Expenses per net KWh	0.0163	0.0094

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: Walters Hydro (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage			1
Conventional			2
1930			3
1930			4
108.00	0.00	0.00	5
113	0	0	6
8,750	0	0	7
			8
113	0	0	9
113	0	0	10
7	0	0	11
477,853,000	0	0	12
			13
712,606	0	0	14
3,472,324	0	0	15
34,543,362	0	0	16
19,455,881	0	0	17
8,258	0	0	18
587,409	0	0	19
58,779,840	0	0	20
544.2578	0.0000	0.0000	21
			22
761,329	0	0	23
0	0	0	24
4,194	0	0	25
30,166	0	0	26
277,721	0	0	27
0	0	0	28
135,139	0	0	29
128,416	0	0	30
385,869	0	0	31
126,891	0	0	32
398,256	0	0	33
2,247,981	0	0	34
0.0047	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Marshall Hydro	1910	5.00	3.0	812,000	13,493,150
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.
2,698,630	46,811		159,310			1
						2
						3
						4
						5
						6
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						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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	Cumberland	Richmond	500.00	500.00	T	56.62		1
2	Cumberland	Wake	500.00	500.00	T	67.26		1
3	Durham	Wake	500.00	500.00	T	27.90		1
4	Mayo	Durham	500.00	500.00	T	45.41		1
5	Mayo	Person	500.00	500.00	T	9.94		1
6	Richmond	Newport (DPC)	500.00	500.00	T	32.69		1
7	Wake	Heritage (VEPCO)	500.00	500.00	T	52.60		1
8	Tot. 500KV Lines							
9	Apex US 1	Cary Regency Park	230.00	230.00	S-HFR	6.95		1
10	Asheboro	Biscoe	230.00	230.00	S-HFR	0.88		1
11	Asheboro	Biscoe	230.00	230.00	W-HFR	24.97		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	8.24		1
14	Asheboro	Siler City	230.00	230.00	S-HFR	1.68		1
15	Asheboro	Siler City	230.00	230.00	C-HFR	15.69		1
16	Asheville Plant	Enka	230.00	230.00	DC T	6.62		2
17	Asheville Plant	Enka	230.00	230.00	S-SP	0.47		1
18	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	DC T	0.18		2
19	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	W-HFR	3.31		1
20	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	S-SP	0.16		1
21	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	W-HFR	3.35		1
22	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	DC T	0.18		2
23	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	S-SP	0.12		1
24	Aurora	Aurora PCS (Black)	230.00	230.00	W-HFR	2.18		1
25	Aurora	Aurora PCS (Black)	230.00	230.00	DC S-HFR	5.49		2
26	Aurora	Aurora PCS (Black)	230.00	230.00	S-SP	0.28		1
27	Aurora	Aurora PCS (White)	230.00	230.00	DC S-HFR	5.47		2
28	Aurora	Aurora PCS (White)	230.00	230.00	S-SP	0.25		1
29	Aurora	Aurora PCS (White)	230.00	230.00	W-HFR	2.20		1
30	Aurora	Greenville	230.00	230.00	DC T	1.78		2
31	Aurora	Greenville	230.00	230.00	W-HFR	36.82		1
32	Aurora	New Bern	230.00	230.00	W-HFR	27.75		1
33	Barnard Creek	Town Creek (Overhead)	230.00	230.00	DC T	1.15		2
34	Barnard Creek	Town Creek (Overhead)	230.00	230.00	W-HFR	0.41		1
35	Barnard Creek	Wilmington Corning Sw Sta	230.00	230.00	W-HFR	3.33		1
36					TOTAL	6,265.27		2,271

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	Barnard Creek	Wilmington Corning Sw Sta	230.00	230.00	S-SP	7.04		1
2	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	7.31		1
3	Biscoe	Rockingham	230.00	230.00	S-HFR	0.77		1
4	Biscoe	Rockingham	230.00	230.00	W-HFR	36.23		1
5	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	S-HFR	1.21		1
6	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	DC T	1.15		2
7	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	W-HFR	24.43		1
8	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	S-SP	7.21		1
9	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	C-SP	0.70		1
10	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	DC T	0.17		2
11	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	W-HFR	29.85		1
12	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	S-HFR	1.13		1
13	Brunswick Plant Unit #1	Jacksonville	230.00	230.00	W-HFR	75.21		1
14	Brunswick Plant Unit #2	Town Creek	230.00	230.00	S-HFR	1.36		1
15	Brunswick Plant Unit #2	Town Creek	230.00	230.00	W-HFR	13.31		1
16	Brunswick Plant Unit #1	Weatherspoon Plant	230.00	230.00	DC T	0.28		2
17	Brunswick Plant Unit #1	Weatherspoon Plant	230.00	230.00	W-HFR	77.65		1
18	Brunswick Plant Unit #2	Delco (West)	230.00	230.00	W-HFR	30.35		1
19	Brunswick Plant Unit #2	Delco (West)	230.00	230.00	S-HFR	1.08		1
20	Brunswick Plant Unit #2	Wallace	230.00	230.00	W-HFR	53.57		1
21	Brunswick Plant Unit #2	Wallace	230.00	230.00	S-HFR	1.25		1
22	Brunswick Plant Unit #2	Whiteville	230.00	230.00	W-HFR	47.74		1
23	Brunswick Plant Unit #2	Whiteville	230.00	230.00	S-HFR	1.07		1
24	Brunswick Plant Unit #1	Brunswick Plt Bus 1A Cap Bk	230.00	230.00	S-HFR	0.12		1
25	Brunswick Plant Unit #1	Brunswick Plt Bus 1B Cap Bk	230.00	230.00	S-HFR	0.08		1
26	Brunswick Plant Unit #2	Brunswick Plt Bus 2A Cap Bk	230.00	230.00	S-HFR	0.12		1
27	Brunswick Plant Unit #2	Brunswick Plt Bus 2B Cap Bk	230.00	230.00	S-HFR	0.08		1
28	Cane River	Nagel East & West(APCO)	230.00	230.00	DC T	15.01		2
29	Cane River	Craggy	230.00	230.00	S-HFR	26.39		1
30	Cape Fear Plant	Cape Fear Plant Cap Bank	230.00	230.00	W-HFR	0.10		1
31	Cape Fear Plant	Harris Plant (North)	230.00	230.00	W-HFR	7.12		1
32	Cape Fear Plant	Harris Plant (North)	230.00	230.00	S-HFR	0.25		1
33	Cape Fear Plant	Harris Plant (South)	230.00	230.00	W-HFR	6.14		1
34	Cape Fear Plant	Harris Plant (South)	230.00	230.00	S-HFR	0.38		1
35	Cape Fear Plant	Jonesboro	230.00	230.00	W-HFR	10.10		1
36					TOTAL	6,265.27		2,271

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	Cape Fear Plant	West End	230.00	230.00	DC T	0.24		2
2	Cape Fear Plant	West End	230.00	230.00	W-HFR	37.30		1
3	Cary Regency Park	Method	230.00	230.00	DC S-SP	0.26		2
4	Cary Regency Park	Method	230.00	230.00	S-SP	4.49		1
5	Cary Regency Park	Method	230.00	230.00	W-HFR	4.00		1
6	Cary Regency Park	RTP	230.00	230.00	S-HFR	11.03		1
7	Castle Hayne	Folkstone	230.00	230.00	S-HFR	0.24		1
8	Castle Hayne	Folkstone	230.00	230.00	W-HFR	24.77		1
9	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	S-SP	0.45		1
10	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	W-HFR	5.12		1
11	Clinton	Erwin	230.00	230.00	S-SP	1.76		1
12	Clinton	Erwin	230.00	230.00	W-HFR	32.03		1
13	Clinton	Erwin	230.00	230.00	S-HFR	0.52		1
14	Clinton	Mt Olive	230.00	230.00	S-HFR	0.27		1
15	Clinton	Mt. Olive	230.00	230.00	S-SP	14.22		1
16	Clinton	Wallace	230.00	230.00	W-HFR	36.68		1
17	Concord	East Danville (AEP)	230.00	230.00	S-HFR	1.21		1
18	Concord	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2
19	Concord	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2
20	Cumberland	Delco	230.00	230.00	W-HFR	54.40		1
21	Cumberland	Fayetteville (North)	230.00	230.00	DC S-SP	5.16		2
22	Cumberland	Fayetteville (North)	230.00	230.00	W-HFR	8.58		1
23	Cumberland	Fayetteville (South)	230.00	230.00	W-HFR	8.57		1
24	Cumberland	Fayetteville (South)	230.00	230.00	DC S-SP	5.16		2
25	Cumberland	Whiteville	230.00	230.00	W-HFR	40.93		1
26	Durham	East Durham (DPC)	230.00	230.00	DC S-HFR	0.75		2
27	Durham	East Durham (DPC)	230.00	230.00	C-HFR	0.60		1
28	Durham	East Durham (DPC)	230.00	230.00	W-HFR	8.31		1
29	Durham	Falls	230.00	230.00	S-HFR	4.28		1
30	Durham	Falls	230.00	230.00	DC S-HFR	3.35		2
31	Durham	Falls	230.00	230.00	S-SP	2.79		1
32	Durham	Falls	230.00	230.00	W-HFR	4.12		1
33	Durham	Method	230.00	230.00	DC S-SP	1.52		2
34	Durham	Method	230.00	230.00	S-SP	1.56		1
35	Durham	Method	230.00	230.00	W-HFR	13.12		1
36					TOTAL	6,265.27		2,271

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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	Durham	RTP	230.00	230.00	S-HFR	0.46		1
2	Durham	RTP	230.00	230.00	W-HFR	7.41		1
3	Durham	RTP	230.00	230.00	S-SP	2.23		1
4	Erwin	Fayetteville East	230.00	230.00	W-HFR	23.09		1
5	Erwin	Milburnie	230.00	230.00	S-HFR	0.50		1
6	Erwin	Milburnie	230.00	230.00	S-SP	0.71		1
7	Erwin	Milburnie	230.00	230.00	DC T	1.33		2
8	Erwin	Milburnie	230.00	230.00	W-HFR	34.08		1
9	Erwin	Selma	230.00	230.00	S-SP	1.08		1
10	Erwin	Selma	230.00	230.00	W-HFR	24.12		1
11	Falls	Milburnie	230.00	230.00	DC T	10.92		2
12	Falls	Milburnie	230.00	230.00	S-HFR	0.32		1
13	Fayetteville	Fayetteville East	230.00	230.00	DC T	0.97		2
14	Fayetteville	Fayetteville East	230.00	230.00	W-HFR	9.82		1
15	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.21		2
16	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.00		1
17	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	W-HFR	17.70		1
18	Fayetteville	Raeford	230.00	230.00	DC S-SP	2.08		2
19	Fayetteville	Raeford	230.00	230.00	W-HFR	14.78		1
20	Fayetteville	Raeford	230.00	230.00	S-HFR	0.16		1
21	Fayetteville	Rockingham	230.00	230.00	W-HFR	49.09		1
22	Fayetteville	Rockingham	230.00	230.00	DC S-HFR	2.30		2
23	Fayetteville	Rockingham	230.00	230.00	DC S-SP	2.08		2
24	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-HFR	6.58		2
25	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.60		1
26	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.27		2
27	Folkstone	Jacksonville	230.00	230.00	W-HFR	20.00		1
28	Folkstone	Jacksonville	230.00	230.00	S-HFR	0.10		1
29	Fort Bragg Woodruff St.	Raeford	230.00	230.00	S-SP	7.20		1
30	Fort Bragg Woodruff St.	Raeford	230.00	230.00	DC S-HFR	2.77		2
31	Fort Bragg Woodruff St.	Raeford	230.00	230.00	S-HFR	19.88		1
32	Greenville	Everetts (VP)	230.00	230.00	DC T	1.83		2
33	Greenville	Kinston Dupont	230.00	230.00	S-HFR	24.82		1
34	Greenville	Kinston Dupont	230.00	230.00	S-SP	0.17		1
35	Greenville	Kinston Dupont	230.00	230.00	DC S-SP	0.33		2
36					TOTAL	6,265.27		2,271

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	Greenville	Wilson	230.00	230.00	W-HFR	33.69		1
2	Greenville	Wilson	230.00	230.00	S-HFR	0.30		1
3	Harris Plant	Siler City	230.00	230.00	S-HFR	1.44		1
4	Harris Plant	Siler City	230.00	230.00	W-HFR	30.04		1
5	Harris Plant	Apex US #1	230.00	230.00	W-HFR	3.13		1
6	Harris Plant	Apex US #1	230.00	230.00	S-HFR	0.87		1
7	Harris Plant	Erwin	230.00	230.00	S-HFR	0.27		1
8	Harris Plant	Erwin	230.00	230.00	W-HFR	29.50		1
9	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	1.15		2
10	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.20		1
11	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	W-HFR	34.30		1
12	Harris Plant	RTP	230.00	230.00	S-SP	17.25		1
13	Harris Plant	RTP	230.00	230.00	S-HFR	3.35		1
14	Harris Plant	Wake	230.00	230.00	S-SP	5.39		1
15	Harris Plant	Wake	230.00	230.00	S-HFR	32.43		1
16	Harris Plant	Harris Plt Start-Up Tran 1A	230.00	230.00	S-SP	0.17		1
17	Harris Plant	Harris Plt Start-Up Tran 1B	230.00	230.00	S-HFR	0.28		1
18	Havelock	Jacksonville	230.00	230.00	DC T	5.61		2
19	Havelock	Jacksonville	230.00	230.00	W-HFR	32.64		1
20	Havelock	Morehead Wildwood	230.00	230.00	DC S-SP	0.27		2
21	Havelock	Morehead Wildwood	230.00	230.00	W-HFR	14.82		1
22	Havelock	Morehead Wildwood	230.00	230.00	S-SP	0.23		1
23	Havelock	New Bern	230.00	230.00	DC T	0.13		2
24	Havelock	New Bern	230.00	230.00	W-HFR	23.34		1
25	Havelock Sub	Havelock Cap Bank	230.00	230.00	S-HFR	0.07		1
26	Henderson	Person	230.00	230.00	DC T	2.46		2
27	Henderson	Person	230.00	230.00	W-HFR	37.47		1
28	Jacksonville	Jacksonville SVC	230.00	230.00	S-HFR	0.10		1
29	Jacksonville	New Bern	230.00	230.00	W-HFR	29.92		1
30	Jacksonville	New Bern	230.00	230.00	S-HFR	0.61		1
31	Jacksonville	Wallace	230.00	230.00	W-HFR	30.82		1
32	Kinston Dupont	Wommack	230.00	230.00	S-SP	0.14		1
33	Kinston Dupont	Wommack	230.00	230.00	S-HFR	19.06		1
34	Laurinburg	Richmond Sub	230.00	230.00	C-SP	3.32		1
35	Laurinburg	Richmond Sub	230.00	230.00	W-HFR	17.12		1
36					TOTAL	6,265.27		2,271

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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	Lee CC Plant	Lee Sub	230.00	230.00	S-HFR	0.87		1
2	Lee Sub	Milburnie	230.00	230.00	S-SP	0.43		1
3	Lee Sub	Milburnie	230.00	230.00	W-HFR	38.24		1
4	Lee Sub	Milburnie	230.00	230.00	DC T	1.36		2
5	Lee Sub	Milburnie	230.00	230.00	S-HFR	0.23		1
6	Lee Sub	Mt. Olive	230.00	230.00	S-HFR	0.23		1
7	Lee Sub	Mt. Olive	230.00	230.00	S-SP	10.39		1
8	Lee Sub	Mt. Olive	230.00	230.00	DC S-HFR	3.21		2
9	Lee Sub	Selma	230.00	230.00	S-SP	0.24		1
10	Lee Sub	Selma	230.00	230.00	W-HFR	16.54		1
11	Lee Sub	Wommack (North)	230.00	230.00	W-HFR	30.37		1
12	Lee Sub	Wommack (South)	230.00	230.00	S-HFR	29.45		1
13	Lilesville	DPC Oakboro (Black)	230.00	230.00	S-HFR	0.30		1
14	Lilesville	DPC Oakboro (Black)	230.00	230.00	DC T	24.40		2
15	Lilesville	DPC Oakboro (White)	230.00	230.00	S-HFR	0.32		1
16	Lilesville	DPC Oakboro (Whilte)	230.00	230.00	DC T	24.38		2
17	LIlesville	Rockingham (Black)	230.00	230.00	S-HFR	10.36		1
18	Lilesville	Rockingham (White)	230.00	230.00	S-HFR	10.35		1
19	Lilesville	Rockingham (South)	230.00	230.00	S-HFR	12.70		1
20	Marion	Whiteville	230.00	230.00	S-SP	14.49		1
21	Marion	Whiteville	230.00	230.00	S-HFR	2.38		1
22	Marion	Whiteville	230.00	230.00	DC S-HFR	5.04		2
23	Method	East Durham (DPC)	230.00	230.00	DC S-HFR	0.77		2
24	Method	East Durham (DPC)	230.00	230.00	S-SP	4.36		1
25	Method	East Durham (DPC)	230.00	230.00	C-HFR	0.55		1
26	Method	East Durham (DPC)	230.00	230.00	W-HFR	14.17		1
27	Method	East Durham (DPC)	230.00	230.00	S-HFR	0.55		1
28	Method	East Durham (DPC)	230.00	230.00	DC S-SP	1.53		2
29	Method	Milburnie	230.00	230.00	DC S-SP	3.64		2
30	Method	Milburnie	230.00	230.00	S-SP	3.79		1
31	Method	Milburnie	230.00	230.00	W-SP	5.31		1
32	Milburnie	Person	230.00	230.00	DC T	58.66		2
33	Milburnie	Person	230.00	230.00	S-HFR	0.49		1
34	Milburnie	Person	230.00	230.00	W-HFR	0.49		1
35	Milburnie	Wake	230.00	230.00	W-HFR	7.19		1
36					TOTAL	6,265.27		2,271

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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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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	New Bern	Wommack (North)	230.00	230.00	S-HFR	2.57		1
2	New Bern	Wommack (North)	230.00	230.00	S-SP	0.14		1
3	New Bern	Wommack (North)	230.00	230.00	W-HFR	29.32		1
4	New Bern	Wommack (South)	230.00	230.00	W-HFR	33.33		1
5	New Bern	Wommack (South)	230.00	230.00	S-HFR	0.54		1
6	Person	Rocky Mount	230.00	230.00	S-HFR	0.13		1
7	Person	Rocky Mount	230.00	230.00	DC S-SP	0.18		2
8	Person	Rocky Mount	230.00	230.00	T	8.59		1
9	Person	Rocky Mount	230.00	230.00	W-HFR	69.41		1
10	Person	Rocky Mount	230.00	230.00	DC T	2.47		2
11	Person	Sedge Hill (VP)	230.00	230.00	W-HFR	4.85		1
12	Raeford	Richmond Substation 230KV	230.00	230.00	W-HFR	33.74		1
13	Raeford	Richmond Substation 230KV	230.00	230.00	S-HFR	1.40		1
14	Raeford	Richmond Substation 230KV	230.00	230.00	S-SP	2.48		1
15	Raeford	Richmond Substation 230KV	230.00	230.00	S-HFR	37.81		1
16	Richmond Sub	Rockingham (East)	230.00	230.00	S-HFR	0.39		1
17	Richmond Sub	Rockingham (East)	230.00	230.00	W-HFR	5.57		1
18	Richmond Sub	Rockingham (West)	230.00	230.00	DC S-HFR	1.21		1
19	Richmond Sub	Rockingham (West)	230.00	230.00	S-HFR	6.63		1
20	Richmond County Plant	Richmond Sub (Black)	230.00	230.00	S-HFR	1.13		1
21	Richmond County Plant	Richmond Sub (White)	230.00	230.00	S-HFR	0.88		1
22	Richmond County Plant	Richmond Sub (Orange	230.00	230.00	S-HFR	1.56		1
23	Robinson Plant	Rockingham	230.00	230.00	DC S-HFR	1.21		2
24	Robinson Plant	Rockingham	230.00	230.00	S-HFR	0.20		1
25	Robinson Plant	Rockingham	230.00	230.00	W-HFR	7.53		1
26	Rockingham	West End (West)	230.00	230.00	DC T	5.73		2
27	Rockingham	West End (West)	230.00	230.00	W-HFR	28.26		1
28	Rockingham	West End (East)	230.00	230.00	DC S-HFR	2.30		2
29	Rockingham	West End (East)	230.00	230.00	S-HFR	29.81		1
30	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC T	4.74		2
31	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC S-SP	0.30		2
32	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC T	4.74		2
33	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC S-SP	0.30		2
34	Rocky Mount	Wilson	230.00	230.00	S-SP	0.85		1
35	Rocky Mount	Wilson	230.00	230.00	DC S-SP	8.26		2
36					TOTAL	6,265.27		2,271

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Rocky Mount	Wilson	230.00	230.00	DC S-HFR	3.68		2
2	Roxboro Plant	East Danville (AEP)	230.00	230.00	S-HFR	1.79		1
3	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2
4	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2
5	Roxboro Plant	Concord	230.00	230.00	S-HFR	0.61		1
6	Roxboro Plant	Falls	230.00	230.00	DC T	47.89		2
7	Roxboro Plant	Falls	230.00	230.00	C-SP	0.21		1
8	Roxboro Plant	Falls	230.00	230.00	S-HFR	0.17		1
9	Roxboro Plant	Falls	230.00	230.00	W-HFR	1.55		1
10	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	C-HFR	1.65		1
11	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	W-HFR	31.99		1
12	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	DC S-HFR	0.76		2
13	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	C-HFR	1.71		1
14	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	W-HFR	31.98		1
15	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	DC S-HFR	0.77		2
16	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	DC T	16.66		2
17	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	C-SP	0.22		1
18	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	DC T	16.66		2
19	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	C-SP	0.22		1
20	Roxboro Plant	Person (Middle)	230.00	230.00	C-HFR	0.10		1
21	Roxboro Plant	Person (Middle)	230.00	230.00	T	0.14		1
22	Roxboro Plant	Person (Middle)	230.00	230.00	S-HFR	1.83		1
23	Roxboro Plant	Person (Ceffo)	230.00	230.00	C-SP	0.21		1
24	Roxboro Palnt	Person (Ceffo)	230.00	230.00	DC T	0.15		2
25	Roxboro Plant	Person (Ceffo)	230.00	230.00	W-HFR	1.90		1
26	Roxboro Plant	Person (Hyco)	230.00	230.00	T	0.08		1
27	Roxboro Plant	Person (Hyco)	230.00	230.00	W-HFR	1.18		1
28	Selma	Wake	230.00	230.00	W-HFR	21.00		1
29	Sutton CC Plant	Sutton Plant	230.00	230.00	S-HFR	0.16		1
30	Sutton Plant	Castle Hayne	230.00	230.00	W-HFR	12.97		1
31	Sutton Plant	Castle Hayne	230.00	230.00	DC T	0.11		2
32	Sutton Plant	Castle Hayne	230.00	230.00	S-HFR	0.93		2
33	Sutton Plant	Delco	230.00	230.00	W-HFR	14.57		1
34	Sutton Plant	Delco	230.00	230.00	S-HFR	0.44		1
35	Sutton Plant	Delco	230.00	230.00	DC T	0.28		2
36					TOTAL	6,265.27		2,271

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Sutton Plant	Wallace	230.00	230.00	T	0.45		1
2	Sutton Plant	Wallace	230.00	230.00	W-HFR	31.89		1
3	Wake	Zebulon	230.00	230.00	W-HFR	10.74		1
4	Wake	Zebulon	230.00	230.00	S-HFR	0.49		1
5	Wayne County Plant	Lee Sub	230.00	230.00	S-HFR	0.35		1
6	Weatherspoon Plant	Fayetteville	230.00	230.00	W-HFR	32.55		1
7	Weatherspoon Plant	Fayetteville	230.00	230.00	DC T	0.97		2
8	Weatherspoon Plant	Latta	230.00	230.00	T	0.37		1
9	Weatherspoon Plant	Latta	230.00	230.00	W-HFR	18.29		1
10	Weatherspoon Plant	Latta	230.00	230.00	DC T	0.28		2
11	Weatherspoon Plant	Laurinburg	230.00	230.00	W-HFR	31.46		1
12	Weatherspoon Plant	Laurinburg	230.00	230.00	S-HFR	0.99		1
13	Wayne County Plant	Lee Substation	230.00	230.00	S-HFR	0.31		1
14	Wilmington Corning SW Sta.	Wilmington Corning Sub. (N)	230.00	230.00	S-SP	0.48		1
15	Wilmington Corning SW Sta.	Wilmington Corning Sub (S)	230.00	230.00	S-SP	0.43		1
16	Wilson	Zebulon	230.00	230.00	W-HFR	25.92		1
17	Wilson	Zebulon	230.00	230.00	S-HFR	0.46		1
18	Tap Point	Angier	230.00	230.00	W-HFR	0.11		1
19	Tap Point	Ansonville	230.00	230.00	S-SP	0.03		1
20	Tap Point	Apex (Bank #1)	230.00	230.00	W-HFR	0.01		1
21	Tap Point	Apex (Bank #2)	230.00	230.00	S-HFR	0.01		1
22	Tap Point	Auburn	230.00	230.00	W-HFR	0.10		1
23	Tap Point	Aurora PCS Mine POD	230.00	230.00	S-HFR	0.02		1
24	Tap Point	Bahama	230.00	230.00	W-HFR	0.06		1
25	Tap Point	Bailey	230.00	230.00	W-HFR	1.38		1
26	Tap Point	Bayboro	230.00	230.00	W-HFR	2.12		1
27	Tap Point	Benson	230.00	230.00	W-HFR	0.01		1
28	Tap Point	Benson PGI	230.00	230.00	W-HFR	1.98		1
29	Tap Point	Bladenboro Solar	230.00	230.00	S-HFR	0.09		1
30	Tap Point	Brunswick EMC Bolivia	230.00	230.00	S-HFR	0.02		1
31	Tap Point	Brunswick EMC Daws Crk	230.00	230.00	S-HFR	0.02		1
32	Tap Point	Buies Creek	230.00	230.00	W-HFR	0.06		1
33	Tap Point	Bynum	230.00	230.00	S-HFR	0.06		1
34	Tap Point	Bynum	230.00	230.00	W-HFR	9.26		1
35	Tap Point	Camp Geiger	230.00	230.00	S-SP	1.94		1
36					TOTAL	6,265.27		2,271

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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	Tap Point	Camp LeJeune Sub #1	230.00	230.00	W-HFR	4.65		1
2	Tap Point	Camp LeJeune Sub #2	230.00	230.00	W-HFR	0.04		1
3	Tap Point	Camp LeJeune French Creek	230.00	230.00	S-SP/S-HFR	2.92		1
4	Tap Point	Cary	230.00	230.00	W-HFR	0.93		1
5	Tap Point	Cary Evans Road (East)	230.00	230.00	W-HFR	0.04		1
6	Tap Point	Cary Evans Road (West)	230.00	230.00	S-HFR	0.04		1
7	Tap Point	Cary Trenton Road	230.00	230.00	S-SP-11	4.34		1
8	Tap Point	Cary Triangle Forest	230.00	230.00	W-HFR	0.04		1
9	Tap Point	Catherine Lake	230.00	230.00	W-HFR	0.08		1
10	Tap Point	Chocowinity	230.00	230.00	W-HFR	0.05		1
11	Tap Point	City of Lumberton POD #3	230.00	230.00	S-SP	0.70		1
12	Tap Point	Clifdale	230.00	230.00	W-HFR	0.54		1
13	Tap Point	Concord	230.00	230.00	S-HFR	0.13		1
14	Tap Point	County Line Solar	230.00	230.00	S-HFR	0.08		1
15	Tap Point	Craven County Wood Energy	230.00	230.00	W-HFR	1.87		1
16	Tap Point	Dover	230.00	230.00	S-HFR	0.04		1
17	Tap Point	Dudley Georgia Pacific	230.00	230.00	W-HFR	2.64		1
18	Tap Point	Eden Solar	230.00	230.00	S-HFR	0.06		1
19	Tap Point	Ellerbe	230.00	230.00	W-HFR	0.04		1
20	Tap Point	Fort Bragg Knox St.	230.00	230.00	W-HFR	0.08		1
21	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	S-SP	0.47		1
22	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	DC S-HFR	2.75		2
23	Tap Point	Fort Bragg Main	230.00	230.00	S-SP	0.04		1
24	Tap Point	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.07		1
25	Tap Point	Four Oaks (East)	230.00	230.00	S-HFR	0.05		1
26	Tap Point	Four Oaks (West)	230.00	230.00	W-HFR	0.07		1
27	Tap Point	Fuquay	230.00	230.00	W-HFR	0.48		1
28	Tap Point	Fuquay Bells Lake	230.00	230.00	W-HFR	0.15		1
29	Tap Point	Garland	230.00	230.00	W-HFR	0.06		1
30	Tap Point	Garner Panther Branch(East)	230.00	230.00	W-HFR	0.15		1
31	Tap Point	Garner Panther Branch(West)	230.00	230.00	S-HFR	0.07		1
32	Tap Point	Grantham	230.00	230.00	W-HFR	0.10		1
33	Tap Point	Hamlet (North)	230.00	230.00	W-HFR	0.02		1
34	Tap Point	Hamlet (South)	230.00	230.00	S-HFR	0.02		1
35	Tap Point	Henderson East	230.00	230.00	W-HFR	0.06		1
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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	Holly Springs (East)	230.00	230.00	S-HFR	0.11		1
2	Tap Point	Holly Springs (West)	230.00	230.00	S-HFR	0.11		1
3	Tap Point	Holly Springs Industrial	230.00	230.00	S-HFR	0.83		1
4	Tap Point	Hope Mills Rockfish Road	230.00	230.00	W-HFR	0.07		1
5	Tap Point	Jacksonville Tarawa	230.00	230.00	W-HFR	0.04		1
6	Tap Point	Knightdale Square D	230.00	230.00	W-HFR	0.95		1
7	Tap Point	Laurel Hills	230.00	230.00	W-HFR	0.03		1
8	Tap Point	Laurinburg City	230.00	230.00	W-HFR	0.03		1
9	Tap Point	Leesville Wood Valley	230.00	230.00	W-HFR	0.15		1
10	Tap Point	Masonboro	230.00	230.00	S-SP	0.03		1
11	Tap Point	Mayo Plant	230.00	230.00	W-HFR	3.06		1
12	Tap Point	Morrisville	230.00	230.00	W-HFR	0.11		1
13	Tap Point	NCSU CBC	230.00	230.00	S-HFR	0.20		1
14	Tap Point	New Bern West	230.00	230.00	W-HFR	0.04		1
15	Tap Point	New Hill	230.00	230.00	W-HFR	0.20		1
16	Tap Point	Newton Grove	230.00	230.00	W-HFR	2.13		1
17	Tap Point	Oxford North	230.00	230.00	W-HFR	0.92		1
18	Tap Point	Oxford South	230.00	230.00	W-HFR	6.30		1
19	Tap Point	Person Sub 230/24kV Bank	230.00	230.00	S-HFR	0.11		1
20	Tap Point	Pitt Greene EMC Farmville	230.00	230.00	S-HFR	0.04		1
21	Tap Point	Pittsboro	230.00	230.00	W-HFR	0.03		1
22	Tap Point	Prospect	230.00	230.00	W-HFR	0.03		1
23	Tap Point	Raleigh Blue Ridge Road	230.00	230.00	S-SP	0.03		1
24	Tap Point	Raleigh Durham Airport	230.00	230.00	W-HFR	0.09		1
25	Tap Point	Raleigh Foxcroft	230.00	230.00	W-HFR	0.03		1
26	Tap Point	Raleigh Homestead (North)	230.00	230.00	S-HFR	0.07		1
27	Tap Point	Raleigh Homestead (South)	230.00	230.00	S-HFR	0.07		1
28	Tap Point	Raleigh Leesville Road	230.00	230.00	W-HFR	0.04		1
29	Tap Point	Raleigh NCSU Centennial	230.00	230.00	S-SP	0.05		1
30	Tap Point	Raleigh Oakdale	230.00	230.00	S-SP	1.26		1
31	Tap Point	Raleigh Six Forks	230.00	230.00	S-HFR	0.07		1
32	Tap Point	Rockingham Aberdeen Road	230.00	230.00	W-HFR	0.60		1
33	Tap Point	Rolesville	230.00	230.00	W-HFR	5.67		1
34	Tap Point	Rose Hill	230.00	230.00	W-HFR	0.16		1
35	Tap Point	Rowan Creek Solar	230.00	230.00	S-HFR	0.07		1
36					TOTAL	6,265.27		2,271

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	Tap Point	Rowland	230.00	230.00	W-HFR	6.86		1
2	Tap Point	Roxboro Bowmantown Road	230.00	230.00	S-HFR	0.04		1
3	Tap Point	Roxboro Cogentrix	230.00	230.00	W-HFR	0.60		1
4	Tap Point	Rox. Plt Unit #3 C. Tower	230.00	230.00	W-HFR	0.24		1
5	Tap Point	Roxboro South	230.00	230.00	W-HFR	0.79		1
6	Tap Point	Sanford Deep River	230.00	230.00	W-HFR	2.63		1
7	Tap Point	Sanford Deep River	230.00	230.00	S-HFR	0.09		1
8	Tap Point	Sanford Garden Street	230.00	230.00	W-HFR	3.25		1
9	Tap Point	Sanford Horner Blvd.	230.00	230.00	W-HFR	0.04		1
10	Tap Point	Sandhills Util. Ft. Brg 3rd	230.00	230.00	S-HFR	0.35		1
11	Tap Point	Scotts Hill	230.00	230.00	S-SP	3.37		1
12	Tap Point	Shoe Heel Creek Solar	230.00	230.00	S-HFR	0.08		1
13	Tap Point	Siler City Hwy. 64	230.00	230.00	S-HFR	0.53		1
14	Tap Point	Southport	230.00	230.00	W-HFR	1.88		1
15	Tap Point	Southport ADM (West)	230.00	230.00	W-HFR	0.48		1
16	Tap Point	Southport Cogentrix	230.00	230.00	W-HFR	0.30		1
17	Tap Point	Swansbsoro	230.00	230.00	W-HFR	0.07		1
18	Tap Point	Tideland EMC Edwards	230.00	230.00	S-SP	0.61		1
19	Tap Point	Topsail	230.00	230.00	W-HFR	1.55		1
20	Tap Point	Town of Apex POD #4	230.00	230.00	S-HFR	0.12		1
21	Tap Point	Town of Farmville	230.00	230.00	S-HFR	0.03		1
22	Tap Point	Turnbull Solar	230.00	230.00	S-HFR	0.07		1
23	Tap Point	Wadesboro	230.00	230.00	S-HFR	0.02		1
24	Tap Point	Wadesboro Bowman School	230.00	230.00	S-HFR	12.98		1
25	Tap Point	Wake Tech	230.00	230.00	S-HFR	0.06		1
26	Tap Point	Warsaw	230.00	230.00	S-SP	0.61		1
27	Tap Point	Warsaw	230.00	230.00	W-HFR	2.46		1
28	Tap Point	Warsaw Solar	230.00	230.00	S-HFR	0.06		1
29	Tap Point	Weatherspoon Sub	230.00	230.00	W-HFR	0.09		1
30	Tap Point	Wendell	230.00	230.00	W-HFR	0.07		1
31	Tap Point	Wilmington Invista	230.00	230.00	W-HFR	0.58		1
32	Tap Point	Wilmington Cedar Avenue	230.00	230.00	S-SP	0.21		1
33	Tap Point	Wilmington East	230.00	230.00	W-HFR	0.01		1
34	Tap Point	Wilmington Ninth & Orange	230.00	230.00	S-SP	2.01		1
35	Tap Point	Wilmington Ogden (East)	230.00	230.00	W-HFR	0.06		1
36					TOTAL	6,265.27		2,271

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Wilmington Ogden (West)	230.00	230.00	S-HFR	0.06		1
2	Tap Point	Wilmington Praxair	230.00	230.00	W-HFR	0.58		1
3	Tap Point	Wilmington BASF	230.00	230.00	W-HFR	0.22		1
4	Tap Point	Wilmington Winter Park	230.00	230.00	S-HFR	0.02		1
5	Tap Point	Yanceyville	230.00	230.00	S-SP	10.36		1
6	Barnard Creek	Town Creek	230.00	230.00	UNDERGROU	1.42		1
7	Bennettsville Sw Sta	Laurinburg	230.00	230.00	S-HFR	0.12		1
8	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	9.90		1
9	Camden	Lugoff(SCPSA)	230.00	230.00	W-HFR	5.37		1
10	Darlington County Plant	Bennettsville Sw Sta	230.00	230.00	S-HFR	0.13		1
11	Darlington County Plant	Bennetsville Sw Sta	230.00	230.00	W-HFR	34.06		1
12	Darlington County Plant	Darlington IC Turbine Yard	230.00	230.00	S-HFR	0.20		1
13	Darlington County Plant	Florence	230.00	230.00	S-SP	37.28		1
14	Darlington County Plant	Robinson Plant (South)	230.00	230.00	W-HFR	1.71		1
15	Darlington County Plant	Robinson Plant (North)	230.00	230.00	S-HFR	1.67		1
16	Darlington County Plant	South Bethune (SCPSA)	230.00	230.00	W-HFR	0.06		1
17	Darlington County Plant	Sumter	230.00	230.00	DC S-SP	5.33		2
18	Darlington County Plant	Sumter	230.00	230.00	W-HFR	48.36		1
19	Florence	Kingstree	230.00	230.00	W-HFR	49.46		1
20	Florence	Latta	230.00	230.00	W-HFR	23.42		1
21	Florence	Latta	230.00	230.00	S-SP	0.17		1
22	Florence	Darlington (SCPSA)	230.00	230.00	W-HFR	11.05		1
23	Latta	Marion	230.00	230.00	W-HFR	8.43		1
24	Marion	Marion (SCPSA) (North)	230.00	230.00	S-HFR	0.07		1
25	Marion	Marion (SCPSA) (South)	230.00	230.00	S-HFR	0.06		1
26	Marion	Whiteville	230.00	230.00	S-SP	6.60		1
27	Marion	Whiteville	230.00	230.00	W-HFR	14.81		1
28	Robinson Plant	Florence	230.00	230.00	DC T	1.40		2
29	Robinson Plant	Florence	230.00	230.00	W-HFR	38.41		1
30	Robinson Plant	Rockingham	230.00	230.00	S-SP	0.23		1
31	Robinson Plant	Rockingham	230.00	230.00	W-HFR	38.95		1
32	Robinson Plant	Rockingham	230.00	230.00	DC T	1.40		2
33	Robinson Plant	Darlington (SCPSA)	230.00	230.00	DC T	0.60		2
34	Robinson Plant	Darlington (SCPSA)	230.00	230.00	W-HFR	17.95		1
35	Robinson Plant	Sumter	230.00	230.00	W-HFR	40.56		1
36					TOTAL	6,265.27		2,271

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

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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	Robinson Plant	Sumter	230.00	230.00	DC T	0.60		2
2	Sumter	St. Geroge (SCE&G)	230.00	230.00	DC T	7.26		2
3	Sumter	St. George (SCE&G)	230.00	230.00	W-HFR	22.90		1
4	Sumter	Wateree Plant (SCE&G)	230.00	230.00	W-HFR	16.58		1
5	Sumter	Wateree Plant (SCE&G)	230.00	230.00	DC T	7.26		2
6	Weatherspoon	Latta	230.00	230.00	W-HFR	13.45		1
7	Tap Point	Bishopville	230.00	230.00	W-HFR	0.16		1
8	Tap Point	Camden 230/23kv Yard	230.00	230.00	W-HFR	0.18		1
9	Tap Point	Cheraw Cash Rd.	230.00	230.00	S-SP	1.08		1
10	Tap Point	Cheraw Reid Park	230.00	230.00	W-HFR	5.30		1
11	Tap Point	Dillon North	230.00	230.00	S-SP	3.51		1
12	Tap Point	Dillon Maple	230.00	230.00	W-HFR	4.39		1
13	Tap Point	Dovesville Nucor	230.00	230.00	W-HFR	6.81		1
14	Tap Point	Elliott	230.00	230.00	W-HFR	2.15		1
15	Tap Point	Florence Cashua	230.00	230.00	C-SP	1.30		1
16	Tap Point	Florence Ebenezer	230.00	230.00	W-HFR	0.08		1
17	Tap Point	Florence West	230.00	230.00	W-HFR	0.03		1
18	Tap Point	Hartsville Segars Mill	230.00	230.00	W-HFR	0.06		1
19	Tap Point	Hartsville Talley Metals	230.00	230.00	W-HFR	0.31		1
20	Tap Point	Hartsville Talley Metals	230.00	230.00	S-SP	0.74		1
21	Tap Point	Kingstree North	230.00	230.00	W-HFR	0.14		1
22	Tap Point	Lake City	230.00	230.00	W-HFR	0.08		1
23	Tap Point	McColl	230.00	230.00	W-HFR	0.90		1
24	Tap Point	Olanta	230.00	230.00	W-HFR	0.05		1
25	Tap Point	Society Hill	230.00	230.00	W-SP	1.13		1
26	Tap Point	Summerton	230.00	230.00	W-HFR	2.70		1
27	Tap Point	Sumter Alice Drive	230.00	230.00	W-HFR	0.30		1
28	Tap Point	Sumter Continental Tire	230.00	230.00	S-HFR	0.31		1
29	Tap Point	Sumter North	230.00	230.00	S-SP	0.73		1
30	Tap Point	Sumter Wedgefield Rd.	230.00	230.00	W-HFR	0.05		1
31	Tap Point	Bayboro	230.00	230.00	S-HFR	0.06		1
32	Tap Point	Powhatan Industrial	230.00	230.00	S-HFR	1.62		1
33	Tap Point	Buckleberry Canal Solar	230.00	230.00	S-HFR	0.10		1
34	Tap Point	Sandy Bottom Solar 230KV	230.00	230.00	S-HFR	0.22		1
35	Tap Point	Willard Solar 230KV Switch	230.00	230.00	S-HFR	0.04		1
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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								
2								
3	Tot. 230kV Lines							
4								
5	Tot. 115kV Lines				Tower and	2,564.49		568
6								
7	Tot. 66kV - 69kV Lines				Tower and	11.92		1,136
8								
9	Expenses (Columns M & N)							
10								
11	Total KV Lines					6,265.27		2,271
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	6,265.27		2,271

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590MCMA(B)								1
1590MCMA(B)								2
3-1590MCMA								3
3-1590MCMA								4
1590MCMA(B)								5
2515MCMA(B)								6
2515MCMA(B)								7
	23,522,235	80,160,869	103,683,104					8
1272MCMA(B)								9
1272MCMA								10
1272MCMA								11
2-1590MCMA								12
1272MCMA(B)								13
1272MCMA(B)								14
1272MCMA(B)								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
1109MCMA								30
1272&1109MCMA								31
1272MCMA								32
2500MCMA								33
2515MCMA								34
1272&2515MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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.
1272MCMA								1
2515MCMA								2
1272MCMA								3
1272MCMA								4
2515MCMA								5
2500MCMA								6
1272&2515MCMA								7
2515MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA								13
2515MCMA								14
2515MCMA								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1590MCMA								28
1590MCMA								29
795MCMA								30
2515&1272MCMA(								31
1272MCMA(B)								32
1272MCMA(B)								33
1272MCMA(B)								34
795&1272MCMA(B)								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								1
1272&2515MCMA								2
2515MCMA								3
2515&1272MCMA								4
1272MCMA(B)								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA								13
1590MCMA								14
1590MCMA								15
1272&556MCMA(B)								16
1590MCMA								17
1590MCMA								18
1590MCMA								19
1272MCMA								20
2515MCMA								21
2515MCMA								22
2515MCMA								23
2515MCMA								24
1272&2515MCMA								25
1272MCMA(B)								26
1272MCMA(B)								27
1272MCMA(B)								28
1590MCMA(B)								29
1590MCMA(B)								30
1590MCMA(B)								31
1272MCMA								32
2515MCMA								33
2515MCMA								34
2515&1272MCMA(								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	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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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.
1272MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA								14
1272MCMA(B)								15
2515&1272MCMA(								16
1272MCMA(B)								17
1272MCMA(B)								18
1272MCMA(B)								19
1272MCMA(B)								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1590MCMA								24
1590MCMA								25
1590MCMA								26
1272MCMA								27
1272MCMA								28
1590MCMA(B)								29
1590MCMA(B)								30
1590MCMA(B)								31
1109MCMA								32
795MCMA(B)								33
795MCMA(B)								34
795MCMA(B)								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	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)
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.
1272&546MCMA(B)								1
1272MCMA								2
1272MCMA(B)								3
2515&1272MCMA(								4
1272MCMA(B)								5
1590MCMA(B)								6
1272MCMA(B)								7
1272MCMA(B)								8
1272MCMA(B)								9
1272MCMA(B)								10
1272MCMA(B)								11
1590MCMA(B)								12
1590MCMA(B)								13
1590MCMA(B)								14
1590MCMA(B)								15
795MCMA								16
2515MCMA(B)								17
1272MCMA								18
1272&556MCMA(B)								19
1590MCMA								20
1590MCMA								21
1590MCMA								22
1272MCMA								23
1272MCMA								24
795MCMA								25
1272MCMA								26
1272MCMA								27
795MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
795MCMA(B)								32
795MCMA(B)								33
2515MCMA								34
2515&1272MCMA(								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590MCMA(B)								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1590MCMA								6
1590MCMA								7
1590MCMA								8
2515&1272MCMA(								9
1272MCMA(B)								10
1272MCMA(B)								11
1272MCMA(B)								12
1272 MCMA								13
1272MCMA								14
1272 MCMA								15
1272MCMA								16
1272 MCMA								17
1272 MCMA								18
2515 MCMA								19
1590MCMA								20
1590MCMA								21
1590MCMA								22
1272MCMA(B)								23
2515MCMA								24
1272MCMA(B)								25
2515&1272MCMA(								26
1272MCMA(B)								27
1272MCMA(B)								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA(B)								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA(B)								12
1272MCMA(B)								13
1590MCMA(B)								14
1590MCMA(B)								15
1272MCMA(B)								16
1272MCMA(B)								17
1590MCMA(B)								18
1590MCMA(B)								19
21590MCMA(B)								20
21590MCMA(B)								21
21590MCMA								22
1590MCMA(B)								23
1590MCMA(B)								24
1272&1590MCMA(								25
1272MCMA								26
1272MCMA								27
2-1590MCMA								28
2-1590MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1590MCMA								34
1590MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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.
1590MCMA								1
1590MCMA								2
1590MCMA								3
1590MCMA								4
1590MCMA								5
1272MCMA								6
1590MCMA								7
1272MCMA								8
1272&1590MCMA								9
1272MCMA(B)								10
1272MCMA(B)								11
1272MCMA(B)								12
1272MCMA(B)								13
1272MCMA(B)								14
1272MCMA(B)								15
1272MCMA(B)								16
1272MCMA(B)								17
1272MCMA(B)								18
1272MCMA(B)								19
1272MCMA(B)								20
1272MCMA(B)								21
1590MCMA(B)								22
1590MCMA(B)								23
1590MCMA(B)								24
1590MCMA(B)								25
2515MCMA								26
1272&2515MCMA(								27
2515&1272MCMA(								28
1590MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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.
1272MCMA								1
1272MCMA								2
1272MCMA(B)								3
1272MCMA(B)								4
1590MCMA(B)								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272&2515MCMA								11
1272MCMA								12
1590MCMA(B)								13
795MCMA								14
795MCMA								15
1272MCMA(B)&251								16
1272MCMA(B)								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
1272MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
1272MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
1272MCMA								30
1272MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
1272MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	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.
795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
1272MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
1272MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.
795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
1272MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
1272MCMA								26
1272MCMA								27
795MCMA								28
1272MCMA								29
795MCMA								30
1272MCMA								31
795MCMA								32
1590MCMA								33
795MCMA								34
795MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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.
795MCMA								1
1272MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
1590MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
1272MCMA								14
1272MCMA								15
795MCMA								16
795MCMA								17
1590MCMA								18
795MCMA								19
795 MCMA								20
795 MCMA								21
795MCMA								22
795MCMA								23
1590MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
1272MCMA								31
795MCMA								32
1272MCMA								33
1272MCMA								34
795MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	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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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
1272MCMA								4
795MCMA								5
2-2500MCMA								6
2515MCMA								7
2515MCMA								8
1272MCMA								9
2515MCMA								10
2515MCMA								11
1590MCMA								12
1590MCMA								13
2515MCMA								14
2515MCMA								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1590MCMA								23
1272MCMA(B)								24
1272MCMA(B)								25
1590MCMA								26
1590MCMA								27
1272MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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.
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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
795MCMA								2
795MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
795MCMA								7
1272MCMA								8
795MCMA								9
1272MCMA								10
795MCMA								11
795MCMA								12
1272MCMA								13
795MCMA								14
795MCMA								15
1590MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
1590MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	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.
								1
								2
	128,566,031	820,743,117	949,309,148					3
								4
	34,741,444	481,595,877	516,337,321					5
								6
	57,228	6,886,984	6,944,212					7
								8
				870,995	12,479,175		13,350,170	9
								10
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	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
	186,886,938	1,389,386,847	1,576,273,785	870,995	12,479,175		13,350,170	36

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Tap Point	Bayboro 230KV Substation	0.06	S-HFR		1	1
2	Tap Point	Powhatan Industrial 230kv S	1.62	S-HFR		1	1
3	Tap Point	Buckleberry Canal Solar	0.10	S-HFR		1	1
4	Tap Point	Sandy Bottom Solar 230kv	0.22	S-HFR		1	1
5	Tap Point	Willard Solar 230kv sw. st.	0.04	S-HFR		1	1
6	Raeford	Richmond 500kv Sub North	37.81	S-HFR		1	1
7	Raeford	Richmond 500kv Sub North	2.48	S-SP		1	1
8							
9	Tap Point	Frazier Solar 115kv Sw. St.	0.04	S-HFR		1	1
10	Tap Point	Louisburg Fox Creek Solar	0.32	S-SP		1	1
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							
42							
43							
44	TOTAL		42.69			9	9

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
795	MCMA	Flat	230		336,463	444,341	463	781,267	1
795	MCMA	Flat	230		1,262,745	2,647,265		3,910,010	2
795	MCMA	Flat	230		106,389			106,389	3
795	MCMA	Flat	230		79,470	74,379		153,849	4
795	MCMA	Flat	230		102,533	102,301		204,834	5
1590	MCMA	Flat	230		3,086,768	3,971,098		7,057,866	6
1590	MCMA	Flat	230		401,430	262,681	41,684	705,795	7
									8
336	MCMA	Flat	115		24,822	37,696		62,518	9
795	MCMA	Flat	115		54,234	69,620		123,854	10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
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									40
									41
									42
									43
					5,454,854	7,609,381	42,147	13,106,382	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Carolina Substations				
2	------------------				
3	Aberdeen 115kV Aberdeen	D-U	115.00	24.00	
4	Amberly 230 kV, Cary	D-U	230.00	24.00	
5	Angier 230kV Angier	D-U	230.00	24.00	
6	Ansonville 230kV Ansonville	D-U	230.00	23.00	
7	Apex 230kV Apex	D-U	230.00	24.00	
8	Archer Lodge 230kV Johnston Co	D-U	230.00	24.00	
9	Arden 115kV Buncombe County	D-U	115.00	24.00	
10	Asheboro 230kV Asheboro	T-U	230.00	115.00	
11	Asheboro East 115kV Asheboro	D-U	115.00	24.00	
12	Asheboro East 115kV Asheboro	T-U	115.00	12.00	
13	Asheboro North 115kV Asheboro	D-U	115.00	24.00	
14	Asheboro South 115kV Asheboro	D-U	115.00	24.00	
15	Asheboro West 115kV Asheboro	D-U	115.00	24.00	
16	Asheville Bent Creek 115kV Asheville	D-U	115.00	24.00	
17	Asheville Rock Hill 115kV Asheville	D-U	115.00	23.00	
18	Asheville S.E. Plant Asheville	T-A	230.00	115.00	
19	Asheville S.E. Plant Asheville	T-A Gen Step-Up 1	115.00	17.20	
20	Asheville S.E. Plant Asheville	T-A Gen Step-Up 2	115.00	19.00	
21	Asheville S.E. Plant Asheville	T-A Gen Set-Up 3,4	115.00	18.00	
22	Atlantic Beach 115kV Morehead	D-U	115.00	12.00	
23	Avery Creek 115 kV Arden	D-U	115.00	24.00	
24	Auburn 230kV Auburn	D-U	230.00	24.00	
25	Bahama 230kV Durham Co.	D-U	230.00	24.00	
26	Bailey 230kV Bailey	D-U	230.00	24.00	
27	Baldwin 115kV Arden	D-U	115.00	24.00	
28	Barnard Creek 230kV Wilmington	T-U	230.00	115.00	
29	Barnardsville 115kV Barnardsville	D-U	115.00	12.00	
30	Bayboro 230kV Bayboro	D-U	230.00	24.00	
31	Bear Branch, Broadway	D-U	230.00	24.00	
32	Beard 115kV Beard	D-U	115.00	13.00	
33	Beaufort 115kV Beaufort	D-U	115.00	12.00	
34	Beaverdam 115kV Asheville	D-U	115.00	24.00	
35	Belfast 115kV Goldsbsoro	D-U	115.00	23.00	
36	Benson 230kV Benson	D-U	230.00	24.00	
37	Beulaville 115kV Beulaville	D-U	115.00	23.00	
38	Biltmore 115kV Asheville	D-U	115.00	12.00	
39	Biscoe 115kV Biscoe	D-U	115.00	24.00	
40	Biscoe 230kV Bisco	T-U	230.00	115.00	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Black Mountain 115kV Black Mountain	D-U	115.00	13.00	
2	Bladenboro 115kV Bladenboro	D-U	115.00	24.00	
3	Blewett H.E. Plant Lilesville	T-A Gen Step-Up	115.00	13.20	
4	Blewett H.E. Plant Lilesville	T-A Gen Step-Up	115.00	4.00	
5	Bridgeton 115kV Bridgeton	D-U	115.00	24.00	
6	Brunswick S.E. Plant Wilmington	T-A Gen Step-Up	230.00	24.00	
7	Buies Creek 230kV Buies Creek	D-U	230.00	24.00	
8	Burgaw 115kV Burgaw	D-U	115.00	23.00	
9	Butler Bldg 115kv Laurinburg NC	D-U	115.00	12.00	
10	Bynum 230kV Bynum	D-U	230.00	24.00	
11	Camp Lejeune French Creek 230kV Jacksonville	D-U	230.00	13.80	
12	Candler 115 kV Candler	D-U	115.00	24.00	
13	Candor 115kV Candor	D-U	115.00	24.00	
14	Cane River 230kV Burnsville	T-U	230.00	115.00	
15	Canton 115kV Canton	D-U	115.00	12.00	
16	Cape Fear S.E. Plant Moncure	T-A	230.00	115.00	13.80
17	Caraleigh 230kV Raleigh	D-U	230.00	24.00	
18	Carolina Beach 115kV Carolina Beach	D-U	115.00	24.00	
19	Carthage 115kV Carthage	D-U	115.00	12.00	
20	Cary 230kV Cary	D-U	230.00	23.00	
21	Cary Evans Rd. 230kV Cary	D-U	230.00	24.00	
22	Cary Piney Plains 230kV Cary	D-U	230.00	24.00	
23	Cary Regency Park 230kV Cary	D-U	230.00	23.00	
24	Cary Trenton Road 230 kV Cary	D-U	230.00	24.00	
25	Cary Triangle Forest 230kV Cary	D-U	230.00	23.00	
26	Castalia 230 kV Castalia	D-U	230.00	24.00	
27	Castle Hayne 115kV Wilmington	D-U	115.00	24.00	
28	Castle Hayne 230kV Wilmington	T-U	230.00	115.00	13.80
29	Catherine Lake 230kV Jacksonville	D-U	230.00	24.00	
30	Chadbourn 115kV Chadbourn	D-U	115.00	24.00	
31	Cherry Point #1 115kV Havelock	D-U	115.00	12.00	
32	Cherry Point #2 115kV Havelock	D-U	115.00	12.00	
33	Chestnut Hills 115kV Raleigh	D-U	115.00	24.00	
34	Chocowinity 230kV Chocowinity	D-U	230.00	23.00	
35	Clarkton 115kV Clarkton	D-U	115.00	24.00	
36	Clayton 115kV Clayton	D-U	115.00	24.00	
37	Clayton Industrial 115kV Clayton	D-U	115.00	24.00	
38	Clifdale 230kV Clifdale	D-U	230.00	24.00	
39	Clinton 230kV Clinton	T-U	230.00	115.00	13.80
40	Clinton Ferrell St. 115kV Clinton	D-U	115.00	23.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Clinton (N) 115kV Clinton	D-U	115.00	23.00	
2	Concord 230kV Concord	T-U	230.00	115.00	
3	Craggy 230kV Craggy	T-U	230.00	115.00	
4	Cumberland 500kV Fayetteville	T-U	500.00	230.00	13.80
5	Delco 115kV Delco	D-U	115.00	24.00	
6	Delco 230kV Delco	T-U	230.00	115.00	13.80
7	Dover 230kV Kinston	D-U	230.00	24.00	
8	Duncan 230kV Garner	D-U	230.00	24.00	
9	Dunn 230kV Dunn	D-U	230.00	23.00	
10	Durham 500kV Leesville	T-U	500.00	230.00	13.80
11	Eagle Island 115kV Wilmington	D-U	115.00	25.00	
12	Edmondson 230kV Raleigh	D-U	230.00	24.00	
13	Elizabethtown 115kV Elizabethtown	D-U	115.00	24.00	
14	Elk Mountain 115kV Asheville	D-U	115.00	24.00	
15	Ellerbe 230kV Ellerbe	D-U	230.00	23.00	
16	Elm City 115kV Elm City	D-U	115.00	24.00	
17	Emma 115kV Asheville	D-U	115.00	12.00	
18	Enka 230kV Enka	T-U	230.00	115.00	
19	Enka Sardis Rd. 115kV Enka	D-U	115.00	24.00	
20	Erwin 230kV Erwin	T-U	230.00	115.00	13.80
21	Erwin 230kV Erwin	D-U	115.00	24.00	12.00
22	Erwin 230kV Erwin	D-U	115.00	24.00	
23	Erwin Mills 115kv Erwin	D-U	115.00	12.00	
24	Fair Bluff 115kV Fair Bluff	D-U	115.00	24.00	
25	Fairmont 115kV Fairmont	D-U	115.00	23.00	
26	Fairview 115kV Fairview	D-U	115.00	12.00	
27	Falls 230kV Raleigh	D-U	230.00	24.00	
28	Falls 230kV Raleigh	T-U	230.00	115.00	
29	Farmville 230kV Farmville	D-U	230.00	12.00	
30	Fayetteville 230kV Fayetteville	D-U	115.00	24.00	13.20
31	Fayetteville 230kV Fayetteville	T-U	230.00	115.00	
32	Fayetteville Slocomb 115kV Slocomb	D-U	115.00	12.00	
33	Folkstone 230kV Holly Ridge	T-U	230.00	115.00	
34	Four Oaks 230kV Four Oaks	D-U	230.00	23.00	
35	Ft Bragg Longstreet Rd 230 kV Fort Bragg	D-U	230.00	12.00	
36	Ft. Bragg Main 230kV Fayetteville	D-U	230.00	23.00	
37	Ft. Bragg Main 230kV Fayetteville	D-U	230.00	12.00	
38	Ft. Bragg Woodruff St. 230kV Fayetteville	T-U	230.00	12.00	
39	Ft. Bragg Woodruff St. 230kV Fayetteville	T-U	230.00	115.00	
40	Franklinton Novo 115kV	D-U	115.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Franklinton 115kV Franklinton	D-U	115.00	24.00	
2	Fremont 115kV Fremont	D-U	115.00	12.00	
3	Fuquay 230kV Fuquay	D-U	230.00	23.00	
4	Fuquay Bells Lake 230kV Fuquay	D-U	230.00	23.00	
5	Garland 230kV Garland	D-U	230.00	23.00	
6	Garner 115kV Garner	D-U	115.00	24.00	
7	Garner I-40 230kV Garner	D-U	230.00	24.00	
8	Garner Panther Branch 230kV Wake Co.	D-U	230.00	23.00	
9	Garner Tryon Hills 115kV Garner	D-U	115.00	24.00	
10	Garner White Oak 230kV Garner	D-U	230.00	24.00	
11	Global Trans Park 115kV Kinston	D-U	115.00	23.00	
12	Godwin 115kV Godwin	D-U	115.00	23.00	
13	Goldsboro City 115kV Goldsboro	D-U	115.00	12.00	
14	Goldsboro Hemlock 115kV Goldsboro	D-U	115.00	12.00	
15	Goldsboro Langston 115kV Goldsboro	D-U	115.00	24.00	
16	Goldsboro-Weil 115kV Goldsboro	D-U	115.00	24.00	
17	Grantham 230kV Grantham	D-U	230.00	24.00	
18	Green Level 230kV Green Level	D-U	230.00	24.00	
19	Grifton 115kV Grifton	D-U	115.00	23.00	
20	Hamlet 230kV Hamlet	D-U	230.00	24.00	
21	Havelock 230kV Havelock	D-U	115.00	23.00	
22	Havelock 230kV Havelock	T-U	230.00	115.00	13.80
23	Hazelwood 115kV Hazelwood	D-U	115.00	24.00	
24	Henderson 230kV Henderson	T-U	230.00	115.00	13.20
25	Henderson 230kV Henderson	D-U	115.00	24.00	
26	Henderson East 230kV Henderson	D-U	230.00	24.00	
27	Henderson North 115kV Henderson	D-U	115.00	24.00	
28	Holly Ridge 115kV Holly Ridge	D-U	115.00	23.00	
29	Holly Springs 230kV Holly Springs	D-U	230.00	24.00	
30	Holly Springs Industrial 230kV Holly Springs	D-U	230.00	24.00	
31	Hope Mills Church St. 115kV Hope Mills	D-U	115.00	23.00	
32	Hope Mills Rockfish Rd. 230kV Hope Mills	D-U	230.00	24.00	
33	Jacksonville 230kV Jacksonville	T-U	230.00	115.00	
34	Jacksonville Blue Creek, Jacksonville	D-U	115.00	24.00	
35	Jacksonville City 115kV Jacksonville	D-U	115.00	24.00	
36	Jacksonville Northwoods 115kV Jacksonville	D-U	115.00	23.00	
37	Jacksonville Tarawa 230kV Jacksonville	D-U	230.00	24.00	
38	Jonesboro 230kV Sanford	D-U	230.00	24.00	
39	Kings Bluff 115kV Wilmington	D-U	115.00	23.00	
40	Kinston 115kV Kinston	D-U	115.00	24.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Kinston DuPont 115kV Kinston	D-U	115.00	12.00	
2	Kinston DuPont 230kV Kinston	T-U	230.00	115.00	
3	Knightdale Hodge Road 230 KV	D-U	230.00	24.00	
4	Knightdale Square D 230kV Knightdale	D-U	230.00	24.00	
5	Knightdale 115kV Knightdale	D-U	115.00	23.00	
6	Kornegay 115kV Kornegay	D-U	115.00	23.00	
7	LaGrange 115kV LaGrange	D-U	115.00	12.00	
8	Lake Junaluska 115kV Lake Junaluska	D-U	115.00	24.00	
9	Lake Wacamaw 115kV Lake Waccamaw	D-U	115.00	24.00	
10	Lakestone 115kV Raleigh	D-U	115.00	12.00	
11	Lakeview 115kv Carthage	D-U	115.00	24.00	
12	Laurel Hill 230kV Laurel Hill	D-U	230.00	23.00	
13	Laurinburg 230kV Laurinburg	T-U	230.00	115.00	13.80
14	Laurinburg 230kV Laurinburg	D-U	115.00	24.00	
15	Laurinburg City 230kV Laurinburg	D-U	230.00	23.00	
16	Lee Combined Cycle Plant	T-A	230.00	115.00	
17	Lee 230kV Goldsboro	T-U	230.00	115.00	
18	Lee 230kV Goldsboro	T-U	115.00	13.80	
19	Leesville Wood Valley 230kV Raleigh	D-U	230.00	24.00	
20	Leicester 115kV Leicester	D-U	115.00	24.00	
21	Leland 115kV Wilmington	D-U	115.00	24.00	
22	Leland Industrial 115kV Leland	D-U	115.00	24.00	
23	Liberty 115kV Liberty	D-U	115.00	23.00	
24	Lillington 115kV Lillington	D-U	115.00	24.00	
25	Littleton 115kV Littleton	D-U	115.00	24.00	
26	Louisburg 115kV Louisburg	D-U	115.00	23.00	
27	Lumberton 115kV Lumberton	D-U	115.00	24.00	
28	Maggie Valley 115kV Maggie Valley	D-U	115.00	24.00	
29	Marshall H.E. Plant Marshall	D-U	115.00	23.00	
30	Marshall H.E. Plant Marshall	T-U Gen Step-Up	23.00	4.00	
31	Masonboro 230kV Wilmington	D-U	230.00	23.00	
32	Maxton 115kV Maxton	D-U	115.00	24.00	
33	Maxton Airport 115kV Maxton	D-U	115.00	23.00	
34	Mayo S.E. Plant Roxboro	T-A Gen Step-Up	500.00	19.90	
35	Method 230kV Raleigh	D-U	115.00	12.00	
36	Method 230kV Raleigh	T-U	230.00	115.00	13.80
37	Micaville 115kV Micaville	D-U	115.00	12.00	
38	Milburnie 230kV Raleigh	D-U	115.00	23.00	
39	Milburnie 230kV Raleigh	T-U	230.00	115.00	13.80
40	Moncure 115kV Moncure	D-U	115.00	24.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Monte Vista 115kV Asheville	D-U	115.00	23.00	
2	Mordecai 115kV Raleigh	D-U	115.00	12.00	
3	Morehead 115kV Morehead	D-U	115.00	12.00	
4	Morehead Wildwood 230kV	D-U	115.00	24.00	
5	Morehead Wildwood 230kV Morehead	T-U	230.00	115.00	
6	Morrisville 230kV Morrisville	D-U	230.00	23.00	
7	Mount Gilead 115kV Mount Gilead	D-U	115.00	12.00	
8	Mount Gilead Industrial 115kV Mount Gilead	D-U	115.00	13.00	
9	Mount Olive 115kV Mount Olive	D-U	115.00	12.00	
10	Mount Olive 230kV Mount Olive	T-U	230.00	115.00	
11	Mount Olive West 115kV Mount Olive	D-U	115.00	24.00	
12	Murrayville 230kV New Hanover	D-U	230.00	23.00	
13	Nagel (APCO) 500kV Hawkins, Tn.	T-U	500.00	230.00	13.80
14	Nashville 115kV Nashville	D-U	115.00	23.00	
15	Neuse 115kV Neuse	D-U	115.00	23.00	
16	New Bern 230kV New Bern	T-U	230.00	115.00	13.20
17	New Bern Amital 115kV New Bern	D-U	115.00	12.00	
18	New Bern West 230kV New Bern	D-U	230.00	23.00	
19	New Hill 230kV New Hill	D-U	230.00	23.00	
20	New Hope 115kV Goldsboro	D-U	115.00	23.00	
21	New Salem 115kV Swannanoa	D-U	115.00	12.00	
22	Newport 115kV Newport	D-U	115.00	23.00	
23	Newton Grove 230kV Newton Grove	D-U	230.00	23.00	
24	North River 115kV Beaufort	D-U	115.00	34.50	
25	Oteen 115kV Asheville	D-U	115.00	12.00	
26	Oxford North 230kV Oxford	D-U	230.00	23.00	
27	Oxford South 230kV Oxford	D-U	230.00	23.00	
28	Pembroke 115kV Pembroke	D-U	115.00	23.00	
29	Person 500kV Roxboro	T-U	500.00	230.00	13.80
30	Person 500kV Roxboro	D-U	230.00	24.00	
31	Pine Lake 230kV Raleigh	D-U	230.00	24.00	
32	Pinehurst 115kV Pinehurst	D-U	115.00	24.00	
33	Pisgah Forest (Duke) 230kV Brevard	T-U	115.00	100.00	13.00
34	Pittsboro 230kV Pittsboro	D-U	230.00	23.00	
35	Powhatan Industrial 230	D-U	230.00	24.00	
36	Princeton 115kV Princeton	D-U	115.00	24.00	
37	Raeford 115kV Raeford	D-U	115.00	12.00	
38	Raeford 230kV Raeford	T-U	230.00	115.00	
39	Raeford South 115kV Raeford	D-U	115.00	12.00	
40	Raleigh 115kV Raleigh	D-U	115.00	12.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Raleigh Atlantic Avenue 115kV Raleigh	D-U	115.00	23.00	
2	Raleigh Blue Ridge 230kV Raleigh	D-U	230.00	23.00	
3	Raleigh Brier Creek 230kV Raleigh	D-U	230.00	24.00	
4	Raleigh Durham Airport 230-23kV Raleigh	D-U	230.00	23.00	
5	Raleigh East St. 230kV Raleigh	D-U	230.00	12.00	
6	Raleigh Foxcroft 230kV Raleigh	D-U	230.00	24.00	
7	Raleigh Harrington Street 115kV Raleigh	D-U	115.00	13.20	
8	Raleigh Homestead 230kV Raleigh	D-U	230.00	24.00	
9	Raleigh Honeycutt 230kV Raleigh	D-U	230.00	24.00	
10	Raleigh Leesville Road 230kV Raleigh	D-U	230.00	24.00	
11	Raleigh Northside 115kV Raleigh	D-U	115.00	12.00	
12	Raleigh Oakdale 230kV Raleigh	D-U	230.00	23.00	
13	Raleigh Prison Farm 230kV Raleigh	D-U	230.00	24.00	
14	Raleigh Six Forks 230kV Raleigh	D-U	230.00	24.00	
15	Raleigh South 115kV Raleigh	D-U	115.00	23.00	
16	Raleigh Timberlake 115kV Raleigh	D-U	115.00	23.00	
17	Raleigh Worthdale 230kV Raleigh	D-U	230.00	23.00	
18	Raleigh Yonkers Rd 115kV Raleigh	D-U	115.00	23.00	
19	Ramseur 115kV Ramseur	T-U	115.00	69.00	12.00
20	Ramseur 115kV Ramseur	D-U	115.00	24.00	
21	Red Springs 115kV Red Springs	D-U	115.00	23.00	
22	Reynolds 115kV Asheville	D-U	115.00	12.00	
23	Rhems 230kV New Bern	D-U	230.00	24.00	
24	Rhems 115kV New Bern	D-U	115.00	24.00	
25	Richmond 500kV Rockingham	T-U	500.00	230.00	13.80
26	Richmond County Plant Hamlet	T-A Gen Step-Up	230.00	18.00	13.80
27	Robbins 115kV Robbins	D-U	115.00	24.00	
28	Rockingham 230kV Rockingham	T-U	230.00	115.00	13.80
29	Rockingham 230kV Rockingham	D-U	115.00	23.00	
30	Rockingham Aberdeen Rd. 230kV Rockingham	D-U	230.00	23.00	
31	Rockingham West 115kV Rockingham	D-U	115.00	24.00	
32	Rocky Mount 230kV Rocky Mount	D-U	115.00	24.00	
33	Rocky Mount 230kV Rocky Mount	T-U	230.00	69.00	13.20
34	Rocky Mount 230kV Rocky Mount	T-U	230.00	115.00	13.80
35	Rocky Point 230KV Rocky Point	D-U	230.00	24.00	
36	Rolesville 230kV Rolesville	D-U	230.00	24.00	
37	Rose Hill 230kV Rose Hill	D-U	230.00	24.00	
38	Roseboro 115kV Roseboro	D-U	115.00	23.00	
39	Rowland 230kV Rowland	D-U	230.00	24.00	
40	Rosewood 115KV Goldsboro	D-U	115.00	24.00	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Roxboro 115kV Roxboro	D-U	115.00	24.00	
2	Roxboro 115kV Roxboro	T-U	115.00	24.00	
3	Roxboro Bowmantown Rd. 230kV Roxboro	D-U	230.00	23.00	
4	Roxboro South 230kV Roxboro	D-U	230.00	24.00	
5	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 1	230.00	22.00	
6	Roxboro S.E. Plant Roxboro	TA Gen St-Dwn ICTG	115.00	4.00	
7	Roxboro S.E. Plant (Cooling Tower) Roxboro	T-A	230.00	4.00	
8	RTP 230KV Morrisville	D-U	230.00	24.00	
9	Samaria 115kV Samaria	D-U	115.00	24.00	
10	Sanford Deep River 230kV Sanford	D-U	230.00	24.00	
11	Sanford Garden St. 230kV Sanford	D-U	230.00	23.00	
12	Sanford Horner Blvd 230kV Sanford	D-U	230.00	24.00	
13	Sanford US #1 230-23kV Sanford	D-U	230.00	24.00	
14	Scotts Hill 230kV Scotts Hill	D-U	230.00	24.00	
15	Seagrove 115kV Seagrove	D-U	115.00	12.00	
16	Selma 230kV Selma	D-U	115.00	12.00	
17	Selma 230kV Selma	D-U	115.00	24.00	13.20
18	Selma 230kV Selma	T-U	230.00	115.00	
19	Seymour Johnson 115kV Goldsboro	D-U	115.00	12.00	
20	Shannon 115kV Shannon	D-U	115.00	23.00	
21	Shearon Harris S.E. Plant New Hill	T-A Gen Step-Up	230.00	21.50	
22	Siler City 115kV Siler City	D-U	115.00	24.00	
23	Siler City 230kV Siler City	T-U	230.00	115.00	13.80
24	Siler City Hwy 64E 230kV Siler City	D-U	230.00	24.00	
25	Skyland 115-23kV Skyland	D-U	115.00	24.00	
26	Smithfield 115kV Smithfield	D-U	115.00	12.00	
27	Snow Hill 115kV Snow Hill	D-U	115.00	23.00	
28	Southern Pines 115kV Southern Pines	D-U	115.00	23.00	
29	Southport 230kV Southport	D-U	230.00	23.00	
30	So. Pines Center Pk. 115kV Southern Pines	D-U	115.00	23.00	
31	Spring Hope 115kV Spring Hope	D-U	115.00	23.00	
32	Spring Lake 115kV Spring Lake	D-U	230.00	24.00	
33	Spruce Pine 115kV Spruce Pine	D-U	115.00	23.00	
34	Stallings Crossroads 115kV Stallings X-Road	D-U	115.00	23.00	
35	St. Pauls 115kV St. Pauls	D-U	115.00	23.00	
36	Sutton CC Plant Wilmington	T-A Gen St-Up SCC01A	115.00	16.50	
37	Sutton S.E. Plant Wilmington	TAGenSt-Up 2A,2B	115.00	13.20	
38	Sutton S.E. Plant Wilmington	TA Gen Step-Up ICTG1	115.00	13.80	
39	Suton CC Plant Wilmington	TA G St-Up STI SCC01	230.00	23.50	
40	Swannanoa 115kV Swannanoa	D-U	115.00	12.00	

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Swansboro 230kV Swansboro	D-U	230.00	23.00	
2	Tillery H.E. Plant Mt. Gilead	T-A Gen Step-Up	115.00	13.20	
3	Topsail 230kV Hampstead	D-U	230.00	23.00	
4	Troy 115kV Troy	D-U	115.00	12.00	
5	Troy Burnette St 115kV Troy	D-U	115.00	12.00	
6	Vander 115kV Vander	T-U	115.00	24.00	
7	Vanderbilt 115kV Asheville	D-U	115.00	12.00	
8	Vander Dak 115kV	D-U	115.00	12.00	
9	Vander Dak/DuPont/Praxair	D-U	115.00	12.00	
10	VIsta 115kV	D-U	115.00	24.00	
11	Wadesboro 230V Wadesboro	D-U	230.00	24.00	
12	Wadesboro-Bowman Sch 230kV Wadesboro	D-U	230.00	24.00	
13	Wake 500kV Knigthdale	T-U	500.00	230.00	13.80
14	Wake Forest 115kV Wake Forest	T-U	115.00	69.00	13.20
15	Wake Tech 230kV Raleigh	D-U	230.00	24.00	
16	Wallace 115kV Wallace	T-U	115.00	69.00	13.20
17	Wallace 115kV Wallace	D-U	115.00	24.00	
18	Wallace 230kV Wallace	T-U	230.00	115.00	13.80
19	Walters H.E.P. Waterville	T-A	161.00	115.00	13.80
20	Walters H.E.P. Waterville	D-A	115.00	12.00	
21	Walters H.E.P. Waterville	T-A Gen Step-Up	115.00	12.00	
22	Walters H.E.P. Waterville	T-A	138.00	115.00	8.60
23	Warrenton 115kV Warrenton	D-U	115.00	24.00	
24	Warsaw 230kV Warsaw	D-U	230.00	24.00	
25	Wayne County Plant	T-A	230.00	18.00	
26	Waynesville 115kV Waynesville	D-U	115.00	12.00	
27	Weatherspoon 230kV Lumberton	D-U	230.00	24.00	
28	Weatherspoon Plant Lumberton	T-A	230.00	115.00	
29	Weatherspoon Plant Lumberton	T-A Gen Step-Up	115.00	13.20	
30	Weaverville 115kV Weaverville	D-U	115.00	12.00	
31	Wendell 230kV Wendell	D-U	230.00	23.00	
32	West Asheville 115kV Asheville	D-U	115.00	12.00	
33	West End 230kV West End	D-U	230.00	24.00	
34	West End 230kV West End	T-U	230.00	115.00	13.80
35	Whiteville 115kV Whiteville	D-U	115.00	23.00	
36	Whiteville 230kV Whiteville	T-U	230.00	115.00	13.80
37	Whiteville SE Regional Park 115kV Whiteville	D-U	115.00	24.00	
38	Wilmington Cedar Ave. 230kV Wilmington	D-U	230.00	23.00	
39	Wilmington East 230kV Wilmington	D-U	230.00	24.00	
40	Wilminton Invista 230 kV Wilmington	D-U	230.00	12.00	

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Wilmington Ogden 230kV Wilmington	D-U	230.00	23.00	
2	Wilm. 9th & Orange 230kV Wilmington	D-U	230.00	24.00	
3	Wilmington River Road 115KV Wilmington	D-U	115.00	24.00	
4	Wilm. Sunset Pk. 115kV Wilmington	D-U	115.00	24.00	
5	Wilm. Winter Pk. 230kV Wilmington	D-U	230.00	23.00	
6	Wilson 230kV Wilson	T-U	230.00	115.00	13.80
7	Wilson's Mills 230kV Wilson's Mills	D-U	230.00	24.00	
8	Wommack 230kV Kinston	T-U	230.00	115.00	13.80
9	Wrightsville Beach 230kV Wrightsville Beach	D-U	230.00	24.00	
10	Yanceyville 230kV Yanceyville	D-U	230.00	12.00	
11	Youngsville 115kV Youngsville	D-U	115.00	24.00	
12	Zebulon 115kV Zebulon	T-U	115.00	69.00	
13	Zebulon 115kV Zebulon	D-U	115.00	24.00	
14	Zebulon 230kV Zebulon	T-U	230.00	115.00	
15	Zebulon 230kV Zebulon	T-U	115.00	69.00	
16					
17					
18	South Carolina Substations				
19	----------------------				
20	Andrews 115kV Andrews	D-U	115.00	24.00	
21	Bennettsville 230kV Bennettsville	D-U	230.00	24.00	
22	Bethune 115kV Bethune	D-U	115.00	12.00	
23	Bishopville 230kV Bishopville	D-U	230.00	24.00	
24	Camden 230kV Camden	D-U	230.00	24.00	
25	Camden 230kV Camden	T-U	230.00	115.00	
26	Camden Steeplechase 115kV Camden	D-U	115.00	24.00	
27	Cheraw 115kV Cheraw	D-U	115.00	24.00	
28	Cheraw Cash Road 230kV Cheraw	D-U	230.00	23.00	
29	Cheraw-Reid Park 230kV Cheraw	D-U	230.00	24.00	
30	Chesterfield 115kV Chesterfield	D-U	115.00	24.00	
31	Darlington 115kV Darlington	D-U	115.00	24.00	
32	Darlington I.C. Plant Darlington	T-A Gen Step-Up	230.00	14.00	
33	Darlington Pineville Rd 115kV Darlington	D-U	115.00	24.00	
34	Dillon 115kV Dillon	D-U	115.00	24.00	
35	Dillon-Maple 230kV Dillon	D-U	230.00	24.00	
36	Dillon North 230kV Dillon	D-U	230.00	24.00	
37	Elgin 115kV Elgin	D-U	115.00	24.00	
38	Elliott 230kV Elliott	D-U	230.00	24.00	
39	Florence 230kV Florence	D-U	115.00	24.00	
40	Florence 230kV Florence	T-U	230.00	115.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Florence Burchs Crossroads 115kV Florence	D-U	115.00	23.00	
2	Florence Cashua 230kV Florence	D-U	230.00	23.00	
3	Florence-Ebenezer 230kV Florence	D-U	230.00	24.00	
4	Florence-Mars Bluff 115kV Florence	D-U	115.00	24.00	
5	Florence-Mount Hope 115kV Florence	D-U	115.00	23.00	
6	Florence-Sardis 230kV Sardis	D-U	230.00	24.00	
7	Florence South 115kV Florence	D-U	115.00	24.00	
8	Florence West 230kV Florence	D-U	230.00	24.00	
9	Hartsville 115kV Hartsville	D-U	115.00	24.00	
10	Hartsville-Segars Mill 230kV Hartsville	D-U	230.00	24.00	
11	Hartsville Sonoco 115kV Hartsville	D-U	115.00	14.00	
12	Hemingway 115kV Hemingway	D-U	115.00	24.00	
13	Jefferson 115kV Jefferson	D-U	115.00	23.00	
14	Kingstree 230kV Kingstree	T-U	230.00	115.00	13.80
15	Kingstree 230kV Kingstree	D-U	115.00	24.00	
16	Kingstree North 230kV Kingstree	D-U	230.00	24.00	
17	Lake City 230kV Lake City	D-U	230.00	24.00	
18	Manning 115kV Manning	D-U	115.00	24.00	
19	Marion 230kV Marion	D-U	115.00	24.00	12.00
20	Marion 230kV Marion	T-U	230.00	115.00	13.80
21	Marion-Bypass 115kV Marion	D-U	115.00	23.00	
22	McColl 230kV McColl	D-U	230.00	24.00	
23	Mullins 115kV Mullins	D-U	115.00	24.00	
24	Nichols 115kV Nichols	D-U	115.00	24.00	
25	Olanta 230kV Olanta	D-U	230.00	24.00	
26	Pageland 115kV Pageland	D-U	115.00	24.00	
27	Pamplico 115kV Pamplico	D-U	115.00	24.00	
28	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	23.00	
29	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	115.00	
30	Shaw Field 115kV Sumter	D-U	115.00	12.00	
31	Society Hill 230kV Society Hill	D-U	230.00	24.00	
32	Summerton 230kV Summerton	D-U	230.00	24.00	
33	Sumter 230kV Sumter	D-U	115.00	23.00	
34	Sumter 230kV Sumter	T-U	230.00	115.00	13.80
35	Sumter Alice Drive 230kV Sumter	D-U	230.00	23.00	
36	Sumter Industrial 115-23kV Sumter	D-U	115.00	23.00	
37	Sumter North 230kV Sumter	D-U	230.00	24.00	
38	Sumter-Wedgefield Rd. 230kV Sumter	D-U	230.00	24.00	
39	Wateree HE.P. (Duke) Sumter	T-A	115.00	100.00	7.00
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2					
3		Total T-A			
4		Total T-U			
5		Total D-A			
6		Total D-U			
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					

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
30	2					3
80	2					4
40	1					5
13	1					6
100	4					7
80	2					8
40	1					9
600	2					10
40	1					11
20	3	1				12
50	2					13
50	2					14
25	1					15
25	1		Mb. Sp.(115/23/12kV)	2	25	16
25	1					17
600	2					18
210	1					19
210	1	1				20
420	2					21
25	1					22
40	1					23
25	1					24
25	1					25
25	1					26
25	1					27
350	2					28
19	3	1				29
48	2					30
40	1					31
25	4					32
25	1	1				33
25	1					34
50	2					35
50	2	1	Step Down 23/12kV	3	13	36
25	1					37
55	1					38
25	1		Mb.Sp.(115/23/12kV)	2	33	39
300	1					40

SUBSTATIONS (Continued)

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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				1
19	3					2
74	1					3
30	1					4
19	3					5
2420	8	1				6
25	1					7
25	1					8
10	3					9
50	2					10
40	1					11
25	1					12
25	1					13
300	3	1				14
80	2					15
650	2					16
63	3					17
50	2					18
25	1					19
50	2					20
90	3					21
90	3					22
50	2					23
24	2					24
50	2					25
25	1					26
100	6					27
500	2					28
25	1					29
19	3					30
50	2					31
26	4					32
100	5	1				33
50	2					34
25	1					35
90	3					36
80	2					37
50	2					38
200	1					39
50	3	1				40

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/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)	
50	2					1
300	1					2
600	2					3
1000	3	1				4
25	1					5
500	2					6
40	1					7
40	1					8
50	2					9
1125	3	1				10
64	4					11
80	2					12
25	1					13
50	2					14
25	1					15
13	2					16
25	1					17
300	1					18
25	1					19
300	2					20
15	3	1				21
25	1					22
25	1					23
7	1					24
40	1					25
30	1					26
40	1					27
600	2					28
25	1					29
25	3	1				30
600	2					31
25	1					32
200	1					33
65	2	1				34
50	2					35
25	1					36
50	2					37
25	1					38
600	2					39
25	1					40

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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
25	1					2
50	2					3
50	2					4
15	3	1				5
50	2					6
40	1					7
90	3					8
40	1					9
40	1					10
13	3					11
23	1					12
50	2					13
25	1					14
40	1					15
25	1					16
25	1					17
40	1					18
25	1					19
65	3					20
50	2					21
400	2					22
65	2					23
600	2					24
50	2					25
50	3					26
50	2					27
9	1					28
80	2					29
40	1					30
25	1					31
39	2					32
600	2					33
40	1					34
50	3	1				35
50	2					36
25	1					37
75	3					38
6	3	2				39
50	2					40

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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)	
100	4					1
300	1					2
24	1					3
25	1					4
50	3	1				5
19	3					6
25	1					7
65	2					8
25	1					9
50	2					10
40	1					11
50	2					12
400	2					13
50	2					14
50	2					15
						16
600	2					17
13	3					18
90	3					19
50	2					20
25	1					21
50	2					22
25	1					23
50	2					24
25	1					25
31	3	1				26
25	1					27
40	1					28
6	1					29
6	1					30
75	3					31
25	1					32
25	1					33
765	3	1				34
50	2					35
600	2					36
13	1	1				37
50	3	1				38
600	2					39
50	2					40

SUBSTATIONS (Continued)

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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.
80	2					1
50	2					2
50	2					3
25	1					4
300	1					5
50	2					6
19	3					7
25	1					8
25	1					9
200	1					10
25	1					11
40	1					12
75		1				13
50	3	1				14
50	2					15
400	2					16
25	1					17
50	2					18
25	1					19
50	3	1				20
30	1					21
25	1					22
25	1					23
50	2			3	1	24
50	3	1				25
50	2					26
50	2					27
40	1					28
1000	3	1				29
25	1					30
54	3					31
80	2					32
100	1					33
25	1					34
24	1					35
24	1					36
55	2					37
420	3					38
15	3					39
50	2					40

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SUBSTATIONS (Continued)

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6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1					1
50	2					2
80	2					3
50	2					4
80	2					5
40	1					6
60	2					7
80	2					8
40	1					9
90	3					10
50	2					11
50	2					12
50	2					13
50	2					14
50	2					15
50	2					16
50	2					17
40	1					18
53	3	2		1	2	19
40	1					20
25	1					21
30	1					22
40	1					23
40	1					24
1500	6	1				25
2765	8					26
25	1					27
550	2		230kV Phase Angle	2	1,080	28
50	3	1				29
25	1					30
75	4	1				31
25	1					32
300	2					33
400	2					34
25	1					35
80	2					36
25	1					37
25	1					38
13	1					39
40	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.
50	3	1				1
60	1					2
25	1					3
50	2					4
795	3					5
27	1					6
40	2	1				7
40	1					8
40	1					9
65	2					10
50	2					11
50	2					12
50	2		23/12Kv Step-Down	4	5	13
65	2					14
13	1					15
19	3	1				16
50	2					17
200	1					18
31	3	1				19
25	1					20
1008	3					21
50	3	1				22
200	1					23
25	1					24
50	2					25
50	3	1				26
25	1					27
50	2					28
50	2					29
50	2					30
25	1					31
40	1					32
50	3	1				33
25	1					34
25	1					35
290	1					36
80	2					37
20	1					38
740	2					39
50	4	1				40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	2					1
110	4					2
40	1					3
25	2					4
30	1					5
25	1					6
50	2					7
50	2					8
48	2					9
40	1					10
50	2					11
25	1					12
2000	6	1	MbSp230-115/24/13/12	4	83	13
50	3	2				14
40	1					15
80	3	1				16
50	2	1				17
150	1					18
336	1					19
5	3					20
150	3	1				21
100	1					22
50	2					23
50	2					24
1186	7					25
20	3	1				26
50	2					27
400	2					28
180	2					29
30	1					30
50	2					31
50	3	1				32
50	2					33
600	2		Mb.Sp.(230/23kV)	1	25	34
17	3	1				35
300	1					36
25	1					37
50	2					38
50	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	04/12/2019	End of 2018/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.
100	4					1
50	2					2
40	1					3
50	3	3				4
90	3					5
600	2					6
40	1					7
400	2					8
100	4					9
25	1					10
40	1					11
50	3	1				12
50	2					13
300	1					14
50	1	1				15
						16
						17
						18
						19
25	1					20
50	2					21
25	1					22
50	2					23
25	1					24
200	1					25
25	1					26
25	1					27
25	1					28
50	2					29
25	1					30
50	3	1				31
1084	8					32
40	1					33
50	3	1				34
25	1					35
25	1					36
23	2					37
25	1					38
75	3					39
600	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
40	1	1				1
25	1					2
25	1					3
25	1					4
50	2					5
40	1					6
50	3	1				7
50	2					8
50	3	1				9
50	2					10
50	2					11
20	3					12
6	1					13
150	1					14
25	1					15
65	2					16
30	3	1				17
25	1					18
25	1					19
400	2					20
50	3	1				21
25	1					22
50	2					23
15	3					24
25	1					25
25	1					26
25	1					27
1320	4	1				28
360	2					29
50	3	1	12/23kV Step-Up	1	25	30
25	1					31
25	1					32
75	3					33
600	2					34
25	1					35
50	3	1				36
50	2					37
50	2					38
154	2					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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
						2
18351						3
24832						4
5						5
13954						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	04/12/2019	End of 2018/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	Services provided by Duke Energy Business Services	Duke Energy Business Services, LLC	Various	653,980,133
3				
4	Customer & Market services	Duke Energy Carolinas, LLC	Various	45,177,566
5	Generation services	Duke Energy Carolinas, LLC	Various	485,821,489
6	Other goods and services	Duke Energy Carolinas, LLC	Various	41,276,539
7	Transmission and Distribution services	Duke Energy Carolinas, LLC	Various	37,001,908
8				
9	Customer & Market services	Duke Energy Florida, LLC	Various	1,441,381
10	Generation services	Duke Energy Florida, LLC	Various	286,717
11	Other goods and services	Duke Energy Florida, LLC	Various	393,876
12	Transmission and Distribution services	Duke Energy Florida, LLC	Various	8,287,069
13				
14	Customer & Market services	Duke Energy Indiana, LLC	Various	265,200
15	Generation services	Duke Energy Indiana, LLC	Various	27,218
16	Other goods and services	Duke Energy Indiana, LLC	Various	236,376
17	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	2,902,261
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Services provided to DE Business Services, LLC	Duke Energy Business Services	Various	2,375,936
22				
23	Customer & Market services	Duke Energy Carolinas, LLC	Various	16,105,686
24	Generation services	Duke Energy Carolinas, LLC	Various	27,184,363
25	Other goods and services	Duke Energy Carolinas, LLC	Various	3,991,897
26	Transmission and Distribution services	Duke Energy Carolinas, LLC	Various	29,411,338
27				
28	Customer & Market services	Duke Energy Florida, LLC	Various	3,238,545
29	Generation services	Duke Energy Florida, LLC	Various	21,877,119
30	Other goods and services	Duke Energy Florida, LLC	Various	2,042,750
31	Transmission and Distribution services	Duke Energy Florida, LLC	Various	3,687,852
32				
33	Customer & Market services	Duke Energy Indiana, LLC	Various	1,709,980
34	Generation services	Duke Energy Indiana, LLC	Various	737,633
35	Other goods and services	Duke Energy Indiana, LLC	Various	949,941
36	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	2,117,613
37				
38	Customer & Market services	Duke Energy Kentucky, Inc.	Various	228,021
39	Generation services	Duke Energy Kentucky, Inc.	Various	220,992
40	Other goods and services	Duke Energy Kentucky, Inc.	Various	294,834
41	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	190,020
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				

Name of Respondent Duke Energy Progress, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/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)
3	Customer & Market services	Duke Energy Ohio, Inc.	Various	182,481
4	Gas Distribution services	Duke Energy Ohio, Inc.	Various	6,893
5	Other goods and services	Duke Energy Ohio, Inc.	Various	281,489
6	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	2,103,113
7				
8	Customer & Market services	Duke Energy Kentucky, Inc.	Various	52,001
9	Gas Distribution services	Duke Energy Kentucky, Inc.	Various	658
10	Generation services	Duke Energy Kentucky, Inc.	Various	18,432
11	Other goods and services	Duke Energy Kentucky, Inc.	Various	
12	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	385,145
13				
14	Gas Distribution services	Piedmont Natural Gas Company, Inc.	Various	77,802,094
15				
16	Other goods and services	Duke Energy Commercial Enterprises	Various	1,085,322
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Customer & Market services	Duke Energy Ohio, Inc.	Various	1,208,586
22	Generation services	Duke Energy Ohio, Inc.	Various	180,204
23	Other goods and services	Duke Energy Ohio, Inc.	Various	120,550
24	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	2,166,108
25				
26	Customer & Market services	Piedmont Natural Gas Company, Inc.	Various	26,837
27	Generation services	Piedmont Natural Gas Company, Inc.	Various	
28	Other goods and services	Piedmont Natural Gas Company, Inc.	Various	246,120
29	Transmission and Distribution services	Piedmont Natural Gas Company, Inc.	Various	125,028
30				
31	Other goods and services	Cinergy Solutions	Various	6,154,411
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 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: 429 Line No.: 4 Column: a

Transactions on this page do not include transactions between Duke Energy Progress and Duke Energy Progress Receivables.

INDEX

Schedule	Page No.